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**BEFORE THE  
NOVA SCOTIA UTILITY AND REVIEW BOARD  
OF THE PROVINCE OF NOVA SCOTIA**

**North American Electric                            )**  
**Reliability Corporation                            )**

**FOURTH QUARTER 2015 APPLICATION  
FOR APPROVAL OF RELIABILITY STANDARDS OF THE  
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION**

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February 26, 2016

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- 1.) Reliability Standards Applicable to Nova Scotia, Approved by FERC in Fourth Quarter 2015;
- 2.) Informational Summary of Each Reliability Standard Applicable to Nova Scotia, Approved by FERC in Fourth Quarter 2015
- 3.) Reliability Standards Filed for Approval; and

**Exhibit B – Updated *Glossary of Terms Used in NERC Reliability Standards***

**Exhibit C – List of Currently Effective NERC Reliability Standards**

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**FOURTH QUARTER 2015 APPLICATION  
FOR APPROVAL OF RELIABILITY STANDARDS OF THE  
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION**

The North American Electric Reliability Corporation (“NERC”) hereby submits to the Nova Scotia Utility and Review Board (“NSUARB”) an application for approval of the NERC Reliability Standards and an updated *Glossary of Terms Used in NERC Reliability Standards* (“NERC Glossary” or “Glossary”) approved by the United States Federal Energy Regulatory Commission (“FERC” or the “Commission”) during the fourth quarter of 2015. This filing covers the time period from October 1, 2015 through December 31, 2015. NERC requests that, as specified herein, these Reliability Standards and the associated NERC Glossary be made mandatory and enforceable for users, owners, and operators of the Bulk-Power System within the Province of Nova Scotia.

In support of this request, NERC submits the following information: (1) a table showing effective dates of each Reliability Standard applicable to Nova Scotia that was approved by FERC in the Fourth Quarter of 2015 (**Exhibit A1**), (2) an informational summary of each Reliability Standard applicable to Nova Scotia that was approved by FERC in the fourth quarter of 2015, including each standard’s purpose, applicability, and filing and approval dates (**Exhibit A2**), (3) Reliability Standards approved by FERC in the fourth quarter of 2015 (**Exhibit A3**); and (4) an updated list of the currently effective NERC Reliability Standards and the associated updated NERC Glossary, as approved by the Commission (see **Exhibit B** and **Exhibit C**,

respectively).<sup>1</sup>

## **I. NOTICES AND COMMUNICATIONS**

Notices and communications regarding this application may be addressed to:

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## **II. REQUEST FOR APPROVAL OF RELIABILITY STANDARDS**

### **A. Background: NERC Quarterly Filing of Proposed Reliability Standards**

Pursuant to Section 215 of the Federal Power Act,<sup>2</sup> NERC has been certified by the Commission as the Electric Reliability Organization in the United States.<sup>3</sup> The Reliability Standards contained in **Exhibit A3** have been approved by the Commission as mandatory and enforceable for users, owners, and operators of the Bulk-Power System within the United States. Some or all of NERC’s Reliability Standards are also mandatory in the Canadian provinces of

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<sup>1</sup> NERC notes that the list of Reliability Standards and NERC Glossary in **Exhibit B** and **Exhibit C** were generated on or around the date of this filing, and, given the quarterly schedule on which this application is filed, these lists may include standards and definitions that were approved after the final day of the previous quarter. Only those standards and definitions highlighted for NSUARB in the present quarterly application and all previous applications should be considered for purposes of today’s application.

<sup>2</sup> 16 U.S.C. § 824o(f) (2012) (entrusting FERC with the duties of approving and enforcing rules in the U.S. to ensure the reliability of the Nation’s bulk power system, and with the duties of certifying an Electric Reliability Organization to develop mandatory and enforceable Reliability Standards, subject to FERC review and approval).

<sup>3</sup> *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (“ERO Certification Order”), *order on reh’g & compliance*, 117 FERC ¶ 61,126 (2006), *aff’d sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

Alberta, British Columbia, Manitoba, New Brunswick, Nova Scotia, Ontario, Québec, and Saskatchewan.

NERC entered into a Memorandum of Understanding (“MOU”) with the NSUARB,<sup>4</sup> and a separate MOU with Nova Scotia Power Incorporated (“NSPI”) and the Northeast Power Coordinating Council, Inc. (“NPCC”),<sup>5</sup> to provide reliability services to Nova Scotia. These MOUs became effective on December 22, 2006 and May 11, 2010, respectively. The December 22, 2006 MOU memorializes the relationship between NERC and the NSUARB formed to improve the reliability of the North American Bulk-Power System. The May 11, 2010 MOU sets forth the mutual understandings of NERC, NSPI, and NPCC regarding the approval and implementation of NERC Reliability Standards and NPCC Regional Reliability Criteria in Nova Scotia and other related matters.

On June 30, 2010, NERC submitted its first set of Reliability Standards and the NERC Glossary to the NSUARB, and on July 20, 2011, NSUARB issued a decision approving these documents.<sup>6</sup> In that decision, the NSUARB approved a “quarterly review” process for considering new and amended NERC Reliability Standards and criteria<sup>7</sup> and ordered that “applications will not be processed by the Board until [FERC] has approved or remanded the standards in the United States.”<sup>8</sup> The NSUARB Decision also stated that NSUARB approval is not required for VRFs and VSLs associated with proposed Reliability Standards, but the

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<sup>4</sup> See Memorandum of Understanding between Nova Scotia Utility and Review Board and North American Electric Reliability Corporation (signed Dec. 22, 2006).

<sup>5</sup> See Memorandum of Understanding between Nova Scotia Power Incorporated and the Northeast Power Coordinating Council, Inc. and the North American Electric Reliability Corporation (signed May 11, 2010).

<sup>6</sup> *In the Matter of an Application by North American Electric Reliability Corporation for Approval of its Reliability Standards, and an application by Northeast Power Coordinating Council, Inc. for Approval of its Regional Reliability Criteria*, NSUARB-NERC-R-10 (July 20, 2011) (“NSUARB Decision”).

<sup>7</sup> *Id.* at P 30.

<sup>8</sup> *Id.*

NSUARB noted that it will accept VRFs and VSLs as guidance.<sup>9</sup>

Based on the NSUARB Decision, NERC applications to the NSUARB only request approval for those Reliability Standards and Glossary definitions approved by FERC during the previous quarter. NERC does not seek formal approval of VRFs and VSLs associated with the Reliability Standards submitted in its quarterly applications. Rather, for informational purposes and for guidance, NERC provides a link below to the FERC-approved VRFs and VSLs associated with NERC Reliability Standards.<sup>10</sup> NERC does not include in its applications the full developmental record for the standards, which consists of the draft standards, comments received, responses to the comments by the drafting teams, and the full voting record, because the record for each standard may consist of several thousand pages. NERC will make the full developmental records available to the NSUARB or other interested parties upon request.

### **B. Overview of NERC Reliability Standards Development Process**

NERC Reliability Standards define the requirements for reliably planning and operating the North American Bulk-Power System. These standards are developed by industry stakeholders using a balanced, open, fair, and inclusive process managed by the NERC Standards Committee. The Standards Committee is facilitated by NERC staff and comprised of representatives from ten electricity stakeholder segments. Stakeholders, through the balloting process, have approved the standards provided in **Exhibit A3**, and the standards have been adopted by the NERC Board of Trustees.

NERC develops Reliability Standards and associated definitions in accordance with Section 300 (Reliability Standards Development) and Appendix 3A (Standards Processes

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<sup>9</sup> *Id.* at P 33.

<sup>10</sup> NERC's VRF Matrix and VSL Matrix are available at: <http://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx?jurisdiction=United States>. See left-hand side of webpage for downloadable documents.

Manual) of its Rules of Procedure.<sup>11</sup> NERC's Reliability Standards development process has been approved by the American National Standards Institute as being open, inclusive, balanced, and fair. The NERC Glossary, most recently updated January 29, 2016, contains each term that is defined for use in one or more of NERC's continent-wide or regional Reliability Standards approved by the NERC Board of Trustees, and it is submitted with this application for informational purposes.

### **C. Description of Proposed Definitions and Reliability Standards, Fourth Quarter 2015**

As explained below, the following six FERC orders were issued in the fourth quarter of 2015 approving NERC Reliability Standards, three related NERC Glossary terms, and a deferred implementation period: (1) a letter order approving an errata to Reliability Standards BAL-003-1, COM-001-2, and VAR-001-4<sup>12</sup> issued on November 13, 2015;<sup>13</sup> (2) a letter order approving Reliability Standards PRC-004-5 and PRC-010-2<sup>14</sup> issued on November 19, 2015; (3) an order approving Reliability Standards EOP-011-1, PRC-010-1 and two revised NERC Glossary definitions<sup>15</sup> issued on November 19, 2015; (4) an order approving nine revised Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) Reliability Standards and two revised NERC Glossary definitions<sup>16</sup> issued on November 19, 2015; (5) a letter order approving Reliability Standards IRO-006-EAST-2 and IRO-009-2<sup>17</sup>

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<sup>11</sup> The NERC *Rules of Procedure* are available at: <http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>.

<sup>12</sup> *N. Am. Elec. Reliability Corp.*, Docket No. RD15-6-000 (Nov. 13, 2015) (unpublished letter order).

<sup>13</sup> The November 13, 2015 letter order in Docket No. RD15-6-000 also included an errata to the implementation plan for PRC-004-4, but because this minor revision has no impact on the standard version number or standard effective date and because NERC does not submit the implementation plans with the NSUARB quarterly filings, NERC does not include information about this revision in this petition.

<sup>14</sup> *N. Am. Elec. Reliability Corp.*, Docket No. RD15-5-000 (Nov. 19, 2015) (unpublished letter order).

<sup>15</sup> *N. Am. Elec. Reliability Corp.*, 153 FERC ¶ 61, 228 (2015).

<sup>16</sup> *N. Am. Elec. Reliability Corp.*, 153 FERC ¶ 61, 178 (2015).

<sup>17</sup> *N. Am. Elec. Reliability Corp.*, Docket No. RD15-7-000 (Dec. 4, 2015) (unpublished letter order).

issued on December 4, 2015; and (6) a letter order approving Reliability Standard PRC-005-6<sup>18</sup> issued on December 18, 2015.

<b>Reliability Standard</b>	<b>Effective Date</b>
<b>Resource and Demand Balancing (BAL) Standard</b>	
BAL-003-1.1	11/13/2015 <sup>19</sup>
<b>Communications (COM) Standard</b>	
COM-001-2.1	11/13/2015
<b>Emergency Preparedness and Operations (EOP) Standard</b>	
EOP-011-1*	4/1/2017
<b>Interconnection Reliability Operations and Coordination (IRO) Standards</b>	
IRO-001-4*	4/1/2017
IRO-002-4*	4/1/2017
IRO-006-EAST-2*	4/1/2016
IRO-008-2*	4/1/2017
IRO-009-2	1/1/2016
IRO-010-2*	1/1/2017
IRO-014-3*	4/1/2017
IRO-017-1*	4/1/2017
<b>Protection and Control (PRC) Standards</b>	
PRC-004-5*	4/2/2017
PRC-005-6	1/1/2016
PRC-010-1*	4/1/2017
PRC-010-2*	4/2/2017
<b>Transmission Operations (TOP) Standards</b>	
TOP-001-3*	4/1/2017
TOP-002-4*	4/1/2017
TOP-003-3*	1/1/2017
<b>Voltage and Reactive (VAR) Standard</b>	
VAR-001-4.1	11/13/2015

\* At the time of this filing, all standards marked with an asterisk are not yet effective, but have been approved by FERC and have a future mandatory effective date.

<sup>18</sup> *N. Am. Elec. Reliability Corp.*, Docket No. RD16-2-000 (Dec. 18, 2015) (unpublished letter order). In connection with NERC's petition to FERC for approval of PRC-005-6, NERC filed a motion to defer the implementation of the FERC-approved versions PRC-005-2, PRC-005-3(i), and PRC-005-4, which FERC granted on December 4, 2015. *N. Am. Elec. Reliability Corp.*, Docket Nos. RM14-8-000, RD15-3-000, RM15-9-000 (Dec. 4, 2015) (unpublished letter order).

<sup>19</sup> Reliability Standard BAL-003-1.1 is implemented based on a phased-in compliance schedule, meaning that individual requirements have compliance dates that are later than the effective date of the Reliability Standard. Because BAL-003-1.1 is an errata and continues to be implemented based on the Commission-approved implementation plan for BAL-003-1, Requirement R1 of BAL-003-1.1 will go into effect on April 1, 2016, and each of the other requirements (R2, R3, and R4) will go into effect on November 13, 2015.



1. BAL-003-1.1

On November 13, 2015, FERC approved an errata filing correcting inadvertent numbering errors and font inconsistencies in Measure M4 of Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting), thus approving Reliability Standard BAL-003-1.1.<sup>20</sup> Reliability Standard BAL-003-1.1 establishes a minimum Frequency Response Obligation for each Balancing Authority; provides a uniform calculation of frequency response; establishes Frequency Bias Settings that set values closer to actual Balancing Authority frequency response; and encourages coordinated automatic generation control (AGC) operation.

2. COM-001-2.1

On November 13, 2015, FERC approved an errata filing correcting inadvertent numbering errors in parts to currently effective Requirement R6 of Reliability Standard COM-001-2 (Communications), thus approving Reliability Standard COM-001-2.1.<sup>21</sup> Reliability Standard COM-001-2.1 establishes a clear set of requirements for what communications capabilities various functional entities must maintain for reliable communications, thereby improving the existing standard.

3. VAR-001-4.1

On November 13, 2015, FERC approved an errata filing to add the word “or” between the words “schedules” and “Reactive” in currently effective Requirement R5, part 5.3 of Reliability Standard VAR-001-4 (Voltage and Reactive Control), thus approving Reliability Standard VAR-

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<sup>20</sup> *N. Am. Elec. Reliability Corp.*, Docket No. RD15-6-000 (Nov. 13, 2015) (unpublished letter order). The original Reliability Standard, BAL-003-1, was approved by the Commission on January 16, 2014. *N. Am. Elec. Reliability Corp.*, 146 FERC ¶ 61,024 (2014).

<sup>21</sup> *N. Am. Elec. Reliability Corp.*, Docket No. RD15-6-000 (Nov. 13, 2015) (unpublished letter order). The original Reliability Standard, COM-001-2, was approved by the Commission on April 16, 2015. *N. Am. Elec. Reliability Corp.*, 151 FERC ¶ 61,039 (2015).

001-4.1.<sup>22</sup> Reliability Standard VAR-001-4.1 sets forth the requirements applicable to Transmission Operators for scheduling, monitoring, and controlling Reactive Power resources in the Real-time Operations, Same-day Operations, and Operational Planning time horizons to regulate voltage and Reactive Power flows for the reliable operation of the Bulk-Power System.

4. PRC-004-5

On November 19, 2015, FERC approved Reliability Standard PRC-004-5 (Protection System Misoperation Identification and Correction), and associated implementation plan and VRFs and VSLs.<sup>23</sup> The purpose of proposed Reliability Standard PRC-004-5 is to identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements. The standard applies to Distribution Providers, Generation Owners, and Transmission Owners. Proposed Reliability Standard PRC-004-5 updates and improves prior versions of PRC-004 by expressly referencing UVLS equipment.

5. PRC-010-2

On November 19, 2015, FERC approved Reliability Standard PRC-010-2 (Undervoltage Load Shedding), and associated implementation plan and VRFs and VSLs.<sup>24</sup> The purpose of PRC-010-2 is to establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (“UVLS Programs”). Proposed PRC-010-2 would replace pending Reliability Standard PRC-010-1. Reliability Standard PRC-010-2 applies to Planning Coordinators and Transmission Planners, because these entities may be responsible for designing and coordinating the UVLS Program.

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<sup>22</sup> *N. Am. Elec. Reliability Corp.*, Docket No. RD15-6-000 (Nov. 13, 2015) (unpublished letter order). The original Reliability Standard, VAR-001-4, was approved by the Commission on August 1, 2014. *N. Am. Elec. Reliability Corp.*, Docket No. RD14-11-000 (Aug. 1, 2014) (unpublished letter order).

<sup>23</sup> *N. Am. Elec. Reliability Corp.*, Docket No. RD15-5-000 (Nov. 19, 2015) (unpublished letter order).

<sup>24</sup> *Id.*

## 6. EOP-011-1

On November 19, 2015, FERC approved Reliability Standard EOP-011-1 (Emergency Operations), associated implementation plans and VRFs and VSLs, and a revised definition of “Energy Emergency” to be included in the NERC Glossary, attached herein as **Exhibit B**.<sup>25</sup> The purpose of Reliability Standard EOP-011-1 is to address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plans to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator area. Reliability Standard EOP-011-1 consolidates the requirements of three existing standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 into a single Reliability Standard that clarifies the critical requirements for Emergency Operations while ensuring strong communication and coordination across the functional entities.

## 7. PRC-010-1

On November 19, 2015, FERC approved Reliability Standard PRC-010-1 (Undervoltage Load Shedding), associated implementation plans and VRFs and VSLs, and a revised definition of “Undervoltage Load Shedding Program (UVLS Program)” to be included in the NERC Glossary and attached herein as **Exhibit B**.<sup>26</sup> The purpose of Reliability Standard PRC-010-1 is to establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding (UVLS) programs. Reliability Standard PRC-010-1 is a single, comprehensive standard that addresses the same reliability principles outlined in the four currently effective UVLS-related Reliability Standards. Reliability Standard PRC-010-1 replaces the applicability to and involvement of “Regional Reliability Organization” in

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<sup>25</sup> *N. Am. Elec. Reliability Corp.*, 153 FERC ¶ 61,228 (2015).

<sup>26</sup> *Id.*

Reliability Standards PRC-020-1 and PRC-021-1 and improves upon and consolidates the four currently-effective UVLS-related Standards into one comprehensive standard.

#### 8. Definition of “Remedial Action Scheme”

On November 19, 2015, FERC approved a revision to the definition of “Remedial Action Scheme” (RAS) to be included in the NERC Glossary, attached herein as **Exhibit B**, the modified Reliability Standards that incorporate the new RAS definition and eliminate use of the term “Special Protection System” (SPS),<sup>27</sup> as well as the associated implementation plan. The defined terms SPS and RAS are currently used interchangeably throughout the NERC Regions and in various Reliability Standards.<sup>28</sup> Revisions to the RAS definition consist of a creation of a “core” definition with a list of objectives and a separate list of exclusions for certain schemes or systems not intended to be covered by the revised definition.

#### 9. TOP and IRO Reliability Standards

On November 19, 2015, FERC approved the following Reliability Standards:

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

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<sup>27</sup> Notably, the RAS versions of PRC-005 (PRC-005-2(ii) and PRC-005-3(ii)) were retired before ever becoming effective under operation of the PRC-005-6 implementation plan.

<sup>28</sup> NERC notes that an active drafting team has developed a revised definition of SPS that references the definition of RAS in order to further the process of completely eliminating this existing definition. That project, Project 2010-05.3 (Phase 3 of Protection Systems: Remedial Action Schemes), is scheduled for completion in 2016.

- IRO-014-3 (Coordination Among Reliability Coordinators); and
- IRO-017-1 (Outage Coordination).

FERC also approved the retirement of the following five currently-effective Reliability Standards:

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

- TOP-008-1 (Response to Transmission Limit Violations).

FERC also approved two revised definitions to the NERC Glossary terms “Operational Planning Analysis” and “Real-time Assessment,” and associated implementation plans and VRFs and VSLs.<sup>29</sup> The TOP and IRO Reliability Standards improve on the currently-effective standards by providing a more precise set of Reliability Standards addressing operating responsibilities and improving the delineation of responsibilities between applicable entities. The revised TOP Reliability Standards eliminate gaps and ambiguities in the currently-effective TOP requirements and improve efficiency by incorporating the necessary requirements from the eight currently-effective TOP Reliability Standards into three comprehensive Reliability Standards. The standards clarify and improve upon the currently-effective TOP and IRO Reliability Standards by designating requirements in the proposed standards that apply to transmission operators for the TOP standards and reliability coordinators for the IRO standards.

#### 10. IRO-006-EAST-2 and IRO-009-2

On December 4, 2015, FERC approved Reliability Standards IRO-006-EAST-2 (Transmission Loading Relief Procedure for the Eastern Interconnection) and IRO-009-2 (Reliability Coordinator Actions to Operate within IROLs), associated implementation plans and VRFs and VSLs, and retirements of the currently effective Reliability Standards IRO-006-EAST-1 and IRO-009-1.<sup>30</sup> Reliability Standard IRO-006-EAST-2 is an improvement to the existing version of the standard because it removes redundant requirements based on “paragraph 81” criteria, revises existing language to clearly delineate applicable entities and the specific actions required, and relocates information in bullet points and subparts to the requirements. Reliability Standard IRO-009-2 is an improvement to the existing version of the standard

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<sup>29</sup> *N. Am. Elec. Reliability Corp.*, 153 FERC ¶ 61,178 (Nov. 19, 2015)

<sup>30</sup> *N. Am. Elec. Reliability Corp.*, Docket No. RD15-7-000 (Dec. 4, 2015) (unpublished letter order).

because it combines two existing requirements, revises existing language to clearly delineate applicable entities and the specific actions required, and removes unnecessary language.

#### 11. PRC-005-6

On December 19, 2015, FERC approved Reliability Standard PRC-005-6 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance), associated implementation plan and VRFs and VSLs, and retirement of previous versions of Reliability Standard PRC-005.<sup>31</sup> Reliability Standard PRC-005-6 represents an improvement upon previous versions of the standard because it requires entities to address supervisory devices associated with certain automatic reclosing relays in their required protection system maintenance programs. The associated implementation plan is designed to supersede implementation of PRC-005 standard versions PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4, and PRC-005-5, so that entities may address all newly-applicable systems in one comprehensive set of revisions to their protection system maintenance programs instead of multiple successive revisions.<sup>32</sup>

#### **D. Additional Commission Action**

Consistent with NERC's commitment to submit FERC-approved VRFs and VSLs associated with NERC Reliability Standards for informational purposes and guidance, NERC highlights for NSUARB FERC's issuance of a letter order on December 4, 2015 approving the VRFs for

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<sup>31</sup> *N. Am. Elec. Reliability Corp.*, Docket No. RD15-2-000 (Dec. 18, 2015) (unpublished letter order).

<sup>32</sup> To allow the implementation plan to operate as intended in the United States, and to avoid having a version of the standard become effective (PRC-005-4) that lacked certain revisions previously approved by FERC in PRC-005-2(i) to clarify the standard's applicability to owners of dispersed generation resources, NERC filed a motion to delay implementation of FERC-approved PRC-005 standard versions PRC-005-3, PRC-005-3(i), and PRC-005-4 until such time that FERC ruled on PRC-005-6. FERC granted this motion on December 4, 2015. *N. Am. Elec. Reliability Corp.*, Docket Nos. RM14-8-000, RD15-3-000, RM15-9-000 (Dec. 4, 2015) (unpublished letter order). As a result of FERC's two orders, Reliability Standards PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4, and PRC-005-5 have been retired in the United States prior to ever becoming effective.

Reliability Standards PRC-004-3, PRC-004-4, and PRC-004-5.<sup>33</sup> These revised VRFs were submitted in accordance with FERC's Order on May 13, 2015 directing NERC to revise the VRFs for PRC-004-3 from "medium" to "high" and to submit a compliance filing highlighting those modifications. The revised VRFs can be found in the NERC VRF Matrix referenced above.

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<sup>33</sup> *N. Am. Elec. Reliability Corp.*, Docket Nos. RD14-14-001, RD15-3-001, RD15-5-001 (Dec. 4, 2015) (unpublished letter order).



### **III. CONCLUSION**

NERC respectfully requests that the NSUARB approve the Reliability Standards and NERC Glossary definitions as specified herein.

Respectfully submitted,

*/s/ Andrew C. Wills*

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**Exhibit A (1): Reliability Standards Applicable to Nova Scotia, Approved by FERC in  
Fourth Quarter 2015**

<b>Reliability Standard</b>	<b>Effective Date</b>
<b>Resource and Demand Balancing (BAL) Standard</b>	
BAL-003-1.1	11/13/2015 <sup>1</sup>
<b>Communications (COM) Standard</b>	
COM-001-2.1	11/13/2015
<b>Emergency Preparedness and Operations (EOP) Standard</b>	
EOP-011-1*	4/1/2017
<b>Interconnection Reliability Operations and Coordination (IRO) Standards</b>	
IRO-001-4*	4/1/2017
IRO-002-4*	4/1/2017
IRO-006-EAST-2*	4/1/2016
IRO-008-2*	4/1/2017
IRO-009-2	1/1/2016
IRO-010-2*	1/1/2017
IRO-014-3*	4/1/2017
IRO-017-1*	4/1/2017
<b>Protection and Control (PRC) Standards</b>	
PRC-004-5*	4/2/2017
PRC-005-6	1/1/2016
PRC-010-1*	4/1/2017
PRC-010-2*	4/2/2017
<b>Transmission Operations (TOP) Standards</b>	
TOP-001-3*	4/1/2017
TOP-002-4*	4/1/2017
TOP-003-3*	1/1/2017
<b>Voltage and Reactive (VAR) Standard</b>	
VAR-001-4.1	11/13/2015

\* At the time of this filing, all standards marked with an asterisk are not yet effective, but have been approved by FERC and have a future mandatory effective date.

<sup>1</sup> Reliability Standard BAL-003-1.1 is implemented based on a phased-in compliance schedule, meaning that individual requirements have compliance dates that are later than the effective date of the Reliability Standard. Because BAL-003-1.1 is an errata and continues to be implemented based on the Commission-approved implementation plan for BAL-003-1, Requirement R1 of BAL-003-1.1 will go into effect on April 1, 2016, and each of the other requirements (R2, R3, and R4) will go into effect on November 13, 2015.

**Exhibit A (2)**

**Informational Summary of Each Reliability Standard Applicable to Nova Scotia, Approved  
by FERC in Fourth Quarter 2015**

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**BAL-003-1.1** - To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

Applicability:

- Balancing Authority
  - The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.
- Frequency Response Sharing Group

Reliability Standard BAL-003-1 includes four requirements, one table detailing interconnection frequency response obligations and another table outlining a timeline for balancing authority frequency response and frequency bias setting activities.

On March 29, 2013, the North American Electric Reliability Corporation (“NERC”) NERC filed a petition for approval of proposed Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) with the Federal Energy Regulatory Commission (“FERC” or “Commission”) in Docket No. RM13-11-000. On August 25, 2015, NERC submitted an errata to the March 29, 2013 petition, requesting approval of BAL-003-1.1 to correct several inadvertent numbering errors as well as font inconsistencies in Measure M4 of BAL-003-1. The Commission approved BAL-003-1.1 on November 13, 2015.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**COM-001-2.1** - To establish Interpersonal Communication capabilities necessary to maintain reliability.

Applicability:

- Transmission Operator
- Balancing Authority
- Reliability Coordinator
- Distribution Provider
- Generator Operator

Reliability Standard COM-001-2.1 includes eleven requirements.

On May 14, 2014, NERC filed a petition for approval of proposed Reliability Standard COM-001-2 (Communications) and COM-002-4 (Operating Personnel Communications Protocols) with the Commission in Docket No. RM14-13-000. On August 25, 2015, NERC submitted an errata to the May 14, 2014 petition, requesting approval of Reliability Standard COM-001-2.1 to correct inadvertent numbering errors in the Parts to Requirement R6. The Commission approved COM-001-2.1 on November 13, 2015.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

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

Applicability:

- Balancing Authority
- Reliability Coordinator
- Transmission Operator

Reliability Standard EOP-011-1 includes six requirements. Along with EOP-011-1, NERC also developed a revised definition of “Energy Emergency.”

On December 29, 2014, NERC submitted a petition for approval of EOP-011-1 and the revised definition of “Energy Emergency” to FERC in Docket No. RM15-7-000, and on November 19, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**IRO-001-4** - To establish the responsibility of Reliability Coordinators to act or direct other entities to act.

Applicability:

- Reliability Coordinator
- Transmission Operator
- Balancing Authority
- Generator Operator
- Distribution Provider

Reliability Standard IRO-001-4 includes three requirements.

On March 18, 2015, NERC submitted a petition for approval of IRO-001-4 to FERC, and on November 19, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**IRO-002-4** - Provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.

Applicability:

- Reliability Coordinator

Reliability Standard IRO-002-4 includes four requirements.

On March 18, 2015, NERC submitted a petition for approval of IRO-002-4 to FERC, and on November 19, 2015, FERC approved the standard.



**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**IRO-006-EAST-2** - To coordinate action between Reliability Coordinators within the Eastern Interconnection when implementing transmission loading relief procedures (TLR) for the Eastern Interconnection to prevent or manage potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).

Applicability:

- Reliability Coordinators in the Eastern Interconnection

Reliability Standard IRO-006-EAST-2 includes two requirements.

On September 16, 2015, NERC submitted a petition for approval of IRO-006-EAST-2 to FERC, and on December 4, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**IRO-008-2** - Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.

Applicability:

- Reliability Coordinator

Reliability Standard IRO-008-2 includes six requirements.

On March 18, 2015, NERC submitted a petition for approval of IRO-008-2 to FERC, and on November 19, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**IRO-009-2** - To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate instances of exceeding Interconnection Reliability Operating Limits (IROLs).

Applicability:

- Reliability Coordinator

Reliability Standard IRO-009-2 includes four requirements.

On September 16, 2015, NERC submitted a petition for approval of IRO-009-2 to FERC, and on December 4, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**IRO-010-2** - To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.

Applicability:

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

Reliability Standard IRO-010-2 includes three requirements.

On March 18, 2015, NERC submitted a petition for approval of IRO-010-2 to FERC, and on November 19, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**IRO-014-3** - To ensure that each Reliability Coordinator's operations are coordinated such that they will not adversely impact other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

Applicability:

- Reliability Coordinator

Reliability Standard IRO-014-3 includes seven requirements.

On March 18, 2015, NERC submitted a petition for approval of IRO-014-3 to FERC, and on November 19, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**IRO-017-1** - To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.

Applicability:

- Reliability Coordinator
- Transmission Operator
- Balancing Authority
- Planning Coordinator
- Transmission Planner

Reliability Standard IRO-017-1 includes four requirements.

On March 18, 2015, NERC submitted a petition for approval of IRO-017-1 to FERC, and on November 19, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**PRC-004-5** - Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

Applicability:

- Transmission Owner
- Generator Owner
- Distribution Provider

Reliability Standard PRC-004-5 includes six requirements and a process flow chart.

On June 8, 2015, and as supplemented on October 23, 2015, NERC submitted a petition for approval of PRC-004-5 to FERC. FERC approved PRC-004-5 on November 19, 2015.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**PRC-005-6** - To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

Applicability:

- Transmission Owner
- Generator Owner
- Distribution Provider

Reliability Standard PRC-005-6 includes five requirements and several tables.

On November 13, 2015, NERC submitted a petition for approval of PRC-005-6 to FERC. Concurrently with the November 13<sup>th</sup> petition, NERC submitted a Motion to Defer Implementation and Request for Shortened Response Period and Expedited Action to the Commission to simplify and streamline the implementation of PRC-005 requirements for all newly-applicable systems in the proposed PRC-005-6 implementation plan. On December 4, 2015, FERC approved NERC's motion to defer implementation, and on December 18, 2015 FERC approved PRC-005-6 and associated implementation plan.



**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**PRC-010-1** - To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).

**Applicability:**

- Planning Coordinator
- Transmission Planner
- Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

Reliability Standard PRC-010-1 includes eight requirements and one table. Along with PRC-010-1, NERC also developed a revised definition of “Undervoltage Load Shedding Program” (“UVLS Program”).

On February 6, 2015, NERC submitted a petition for approval of PRC-010-1 and the revised definition of “Undervoltage Load Shedding Program” (“UVLS Program”) to FERC, and on November 19, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**PRC-010-2** - To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).

Applicability:

- Planning Coordinator
- Transmission Planner
- Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

Reliability Standard PRC-010-2 includes eight requirements and one table.

On June 8, 2015, NERC submitted a petition for approval of PRC-010-2 to FERC, and on November 19, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**TOP-001-3** - To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

Applicability:

- Balancing Authority
- Transmission Operator
- Generator Operator
- Distribution Provider

Reliability Standard TOP-001-3 includes twenty requirements.

On March 18, 2015, NERC submitted a petition for approval of TOP-001-3 to FERC, and on November 19, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**TOP-002-4** - To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.

Applicability:

- Transmission Operator
- Balancing Authority

Reliability Standard TOP-002-4 includes seven requirements.

On March 18, 2015, NERC submitted a petition for approval of TOP-002-4 to FERC, and on November 19, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**TOP-003-3** - To ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities.

Applicability:

- Transmission Operator
- Balancing Authority
- Generator Owner
- Generator Operator
- Load-Serving Entity
- Transmission Owner
- Distribution Provider

Reliability Standard TOP-003-3 includes five requirements.

On March 18, 2015, NERC submitted a petition for approval of TOP-003-3 to FERC, and on November 19, 2015, FERC approved the standard.

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia,  
Approved by FERC in Fourth Quarter 2015**

**VAR-001-4.1** - To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

Applicability:

- Transmission Operators
- Generator Operators within the Western Interconnection (for the WECC Variance)

Reliability Standard VAR-001-4.1 includes six requirements.

On June 9, 2014, NERC filed a petition for approval of proposed Reliability Standard VAR-001-4 (Voltage and Reactive Control) and VAR-002-3 (Generator Operation for Maintaining Network Voltage Schedules) with the Commission in Docket No. RD14-11-000. On August 25, 2015, NERC submitted an errata to the June 9, 2014 petition, requesting approval of Reliability Standard VAR-001-4.1 to correct inadvertent omission of the word “or” between the words “schedules” and “Reactive” in both the clean and redline Requirement R5, part 5.3 of VAR-001.4. The Commission approved VAR-001-4 on November 13, 2015.

**Exhibit A (3)**  
**Reliability Standards Filed for Approval**

**Reliability Standard BAL-003-1.1**



## A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**
2. **Number: BAL-003-1.1**
3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.
4. **Applicability:**
  - 4.1. Balancing Authority
    - 4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.
  - 4.2. Frequency Response Sharing Group
5. **Effective Date:**
  - 5.1. In those jurisdictions where regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after Board of Trustees adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after Board of Trustees adoption.

## B. Requirements

- R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. [*Risk Factor: High*][*Time Horizon: Real-time Operations*]

- R2.** Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. [*Risk Factor: Medium*][*Time Horizon: Operations Planning*]
- R3.** Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: [*Risk Factor: Medium*][*Time Horizon: Operations Planning*]
- 3.1** Less than zero at all times, and
- 3.2** Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.
- R4.** Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: [*Risk Factor: Medium*][*Time Horizon: Operations Planning*]
- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or
  - The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

**C. Measures**

- M1.** Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.
- M2.** The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.
- M3.** The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of

the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

- M4.** The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

## **D. Compliance**

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

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

The Regional Entity is the Compliance Enforcement Authority except where the responsible entity works for the Regional Entity. Where the responsible entity works for the Regional Entity, the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity), to be responsible for compliance enforcement.

#### **1.2 Compliance Monitoring and Assessment Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

#### **1.3 Data Retention**

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

The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

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

**1.4 Additional Compliance Information**

For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

**2.0 Violation Severity Levels**

R#	Lower VSL	Medium VSL	High VSL	Severe VSL
R1	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO
R2	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation

**Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting**

	calendar days from the implementation period specified by the ERO.	days from the implementation period specified by the ERO.	days from the implementation period specified by the ERO.	period specified by the ERO.
R3	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%..
R4	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value.  OR The Balancing Authority failed to change the

				Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.
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**E. Regional Variance**

None

**F. Associated Documents**

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

**G. Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial; updated version number to “0.1b”	Errata

**Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting**

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0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata

## Attachment A

### BAL-003-1 Frequency Response & Frequency Bias Setting Standard

#### Supporting Document

#### Interconnection Frequency Response Obligation (IFRO)

The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:

- Prevailing UFLS first step
- $CC_{Adj}$  which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data
- $CB_R$  which is the statistically determined ratio of the Point C to Value B
- $BC'_{Adj}$  which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.

The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment ( $BC'_{Adj}$ ) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

Interconnection	Eastern	Western	ERCOT	HQ	Units
Starting Frequency ( $F_{Start}$ )	59.974	59.976	59.963	59.972	Hz
Prevailing UFLS First Step	59.5*	59.5	59.3	58.5	Hz
Base Delta Frequency ( $DF_{Base}$ )	0.474	0.476	0.663	1.472	Hz
$CC_{ADJ}$	0.007	0.004	0.012	N/A	Hz
Delta Frequency ( $DF_{CC}$ )	0.467	0.472	0.651	1.472	Hz
$CB_R$	1.000	1.625	1.377	1.550	
Delta Frequency ( $DF_{CBR}$ )	0.467	0.291	0.473	0.949	Hz
$BC'_{ADJ}$	0.018	N/A	N/A	N/A	Hz
Max. Delta Frequency (MDF)	0.449	0.291	0.473	0.949	
Resource Contingency Criteria (RCC)	4,500	2,740	2,750	1,700	MW
Credit for Load Resources (CLR)		300	1,400**		MW
IFRO	-1,002	-840	-286	-179	MW/0.1 Hz

Table 1: Interconnection Frequency Response Obligations



## Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

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*\*The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*

*\*\*In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*

An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.

### Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting

The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.

For a multiple Balancing Authority interconnection, the Interconnection Frequency Response Obligation shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$FRO_{BA} = IFRO \times \frac{\text{Annual Gen}_{BA} + \text{Annual Load}_{BA}}{\text{Annual Gen}_{Int} + \text{Annual Load}_{Int}}$$

Where:

- Annual Gen<sub>BA</sub> is the total annual “Output of Generating Plants” within the Balancing Authority Area (BAA), on FERC Form 714, column c of Part II - Schedule 3.
- Annual Load<sub>BA</sub> is total annual Load within the BAA, on FERC Form 714, column e of Part II - Schedule 3.
- Annual Gen<sub>Int</sub> is the sum of all Annual Gen<sub>BA</sub> values reported in that interconnection.
- Annual Load<sub>Int</sub> is the sum of all Annual Load<sub>BA</sub> values reported in that interconnection.

The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO’s.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that contains the sum of each participant’s individual event performance.

## **Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting**

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Balancing Authorities that merge or that transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A BA using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the BA chooses between 100% and 125% of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a Frequency Response Sharing Group will need to calculate its stand-alone Frequency Response Measure using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined BAs' areas on FRS Form 1 as described in Requirement R4.

There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.

If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.

If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.

### **Frequency Response Measure (FRM)**

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its

## Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

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Frequency Response, expressed in MW/0.1Hz” as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change in its Net Actual Interchange on its tie lines with its adjacent Balancing Authorities divided by the change in Interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA<sub>i</sub>) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year. As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.) The ERO will use a standardized sampling interval of approximately 16 seconds before the event up to the time of the event for the pre-event NA<sub>i</sub> and frequency (A values) and approximately 20 to 52 seconds after the event for the post-event NA<sub>i</sub> (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority’s Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt or its EMS was unavailable. FRS Form 2 has instructions on how to correct the BA’s data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct FRS Form 1 will automatically calculate the Balancing Authority’s FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing authorities to plan its operations, events with a “Point C” that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that interconnection. However, the calculation of the BA response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

### **Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities**

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities (BA) to:

- Facilitate the assignment of BA Frequency Response Obligations (FRO)
- Calculate BA Frequency Response Measures (FRM)
- Determine BA Frequency Bias Settings (FBS)

## Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

Target Date	Activity
April 30	The ERO reviews candidate frequency events and selects frequency events for the first quarter (December to February).
May 10	Form1 is posted with selected events from the first quarter for BA usage by the ERO.
May 15	The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.
July 15	The BAs provide load and generation data as described in Attachment A to the ERO.
July 30	The ERO reviews candidate frequency events and selects frequency events for the second quarter (March to May).
August 10	Form1 is posted with selected events from the first and second quarters for BA usage by the ERO.
October 30	The ERO reviews candidate frequency events and selects frequency events for the third quarter (June to August)
November 10	Form1 is posted with selected events from the first, second, and third quarters for BA usage by the ERO.
November 20	If necessary, the ERO provides any updates to the necessary Frequency Response.
November 20	The ERO provides the fractional responsibility of each BA for the Interconnection's FRO and Minimum FBS to the BAs.
January 30	The ERO reviews candidate frequency events and selects frequency events for the fourth quarter (September to November).
2 <sup>nd</sup> business day in February	Form1 is posted with all selected events for the year for BA usage by the ERO.
February 10	The ERO assigns FRO values to the BAs for the upcoming year.
March 7	BAs complete their frequency response sampling for all four quarters and their FBS calculation, returning the results to the ERO.
March 24	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection, and determines L10 values for the CPS 2 criterion for each BA as applicable.
Any time during first 3 business days of April (unless specified otherwise by the ERO)	The BA implements any changes to their FBS and L10 value.

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
BAL-003-1.1	R1.	04/01/2016	
BAL-003-1.1	R2.	04/01/2015	
BAL-003-1.1	R3.	04/01/2015	
BAL-003-1.1	3.1.	04/01/2015	
BAL-003-1.1	3.2.	04/01/2015	
BAL-003-1.1	R4.	04/01/2015	

**Reliability Standard COM-001-2.1**

## Standard COM-001-2.1 — Communications

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### A. Introduction

1. **Title:** **Communications**
2. **Number:** COM-001-2.1
3. **Purpose:** To establish Interpersonal Communication capabilities necessary to maintain reliability.
4. **Applicability:**
  - 4.1. Transmission Operator
  - 4.2. Balancing Authority
  - 4.3. Reliability Coordinator
  - 4.4. Distribution Provider
  - 4.5. Generator Operator
5. **Effective Date:** The first day of the second calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

### B. Requirements

- R1. Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
  - 1.1. All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.
  - 1.2. Each adjacent Reliability Coordinator within the same Interconnection.
- R2. Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
  - 2.1. All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.
  - 2.2. Each adjacent Reliability Coordinator within the same Interconnection.
- R3. Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
  - 3.1. Its Reliability Coordinator.
  - 3.2. Each Balancing Authority within its Transmission Operator Area.

## Standard COM-001-2.1 — Communications

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- 3.3. Each Distribution Provider within its Transmission Operator Area.
  - 3.4. Each Generator Operator within its Transmission Operator Area.
  - 3.5. Each adjacent Transmission Operator synchronously connected.
  - 3.6. Each adjacent Transmission Operator asynchronously connected.
- R4.** Each Transmission Operator shall designate an Alternative Interpersonal Communication capability with the following entities: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]
- 4.1. Its Reliability Coordinator.
  - 4.2. Each Balancing Authority within its Transmission Operator Area.
  - 4.3. Each adjacent Transmission Operator synchronously connected.
  - 4.4. Each adjacent Transmission Operator asynchronously connected.
- R5.** Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]
- 5.1. Its Reliability Coordinator.
  - 5.2. Each Transmission Operator that operates Facilities within its Balancing Authority Area.
  - 5.3. Each Distribution Provider within its Balancing Authority Area.
  - 5.4. Each Generator Operator that operates Facilities within its Balancing Authority Area.
  - 5.5. Each Adjacent Balancing Authority.
- R6.** Each Balancing Authority shall designate an Alternative Interpersonal Communication capability with the following entities: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]
- 6.1. Its Reliability Coordinator.
  - 6.2. Each Transmission Operator that operates Facilities within its Balancing Authority Area.
  - 6.3. Each Adjacent Balancing Authority.
- R7.** Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]
- 7.1. Its Balancing Authority.
  - 7.2. Its Transmission Operator.



## Standard COM-001-2.1 — Communications

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- R8.** Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
- 8.1.** Its Balancing Authority.
  - 8.2.** Its Transmission Operator.
- R9.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations, Same-day Operations]*
- R10.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
- R11.** Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

### C. Measures

- M1.** Each Reliability Coordinator shall have and provide upon request evidence that it has Interpersonal Communication capability with all Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and with each adjacent Reliability Coordinator within the same Interconnection, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R1.)
- M2.** Each Reliability Coordinator shall have and provide upon request evidence that it designated an Alternative Interpersonal Communication capability with all Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and with each adjacent Reliability Coordinator within the same Interconnection, which could include, but is not limited to:
- physical assets, or

## Standard COM-001-2.1 — Communications

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- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R2.)
- M3.** Each Transmission Operator shall have and provide upon request evidence that it has Interpersonal Communication capability with its Reliability Coordinator, each Balancing Authority, Distribution Provider, and Generator Operator within its Transmission Operator Area, and each adjacent Transmission Operator asynchronously or synchronously connected, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communication. (R3.)
- M4.** Each Transmission Operator shall have and provide upon request evidence that it designated an Alternative Interpersonal Communication capability with its Reliability Coordinator, each Balancing Authority within its Transmission Operator Area, and each adjacent Transmission Operator asynchronously and synchronously connected, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R4.)
- M5.** Each Balancing Authority shall have and provide upon request evidence that it has Interpersonal Communication capability with its Reliability Coordinator, each Transmission Operator and Generator Operator that operates Facilities within its Balancing Authority Area, each Distribution Provider within its Balancing Authority Area, and each adjacent Balancing Authority, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R5.)
- M6.** Each Balancing Authority shall have and provide upon request evidence that it designated an Alternative Interpersonal Communication capability with its Reliability Coordinator, each Transmission Operator that operates Facilities within its Balancing Authority Area, and each adjacent Balancing Authority, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R6.)

## Standard COM-001-2.1 — Communications

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- M7.** Each Distribution Provider shall have and provide upon request evidence that it has Interpersonal Communication capability with its Transmission Operator and its Balancing Authority, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R7.)
- M8.** Each Generator Operator shall have and provide upon request evidence that it has Interpersonal Communication capability with its Balancing Authority and its Transmission Operator, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R8.)
- M9.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have and provide upon request evidence that it tested, at least once each calendar month, its Alternative Interpersonal Communication capability designated in Requirements R2, R4, or R6. If the test was unsuccessful, the entity shall have and provide upon request evidence that it initiated action to repair or designated a replacement Alternative Interpersonal Communication capability within 2 hours. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R9.)
- M10.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have and provide upon request evidence that it notified entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasted 30 minutes or longer. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R10.)
- M11.** Each Distribution Provider and Generator Operator that detected a failure of its Interpersonal Communication capability shall have and provide upon request evidence that it consulted with each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine mutually agreeable action to restore the Interpersonal Communication capability. Evidence could include, but is not limited to: dated operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R11.)

### **D. Compliance**

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

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

## Standard COM-001-2.1 — Communications

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

### 1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

### 1.3. Data Retention

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

- The Reliability Coordinator for Requirements R1, R2, R9, and R10, Measures M1, M2, M9, and M10 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Transmission Operator for Requirements R3, R4, R9, and R10, Measures M3, M4, M9, and M10 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Balancing Authority for Requirements R5, R6, R9, and R10, Measures M5, M6, M9, and M10 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Distribution Provider for Requirements R7 and R11, Measures M7 and M11 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Generator Operator for Requirements R8 and R11, Measures M8 and M11 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.

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

## **Standard COM-001-2.1 — Communications**

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

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

None.

**Standard COM-001-2.1 — Communications**

**2. Violation Severity Levels**

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	The Reliability Coordinator failed to have Interpersonal Communication capability with one of the entities listed in Requirement R1, Parts 1.1 or 1.2, except when the Reliability Coordinator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.	The Reliability Coordinator failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R1, Parts 1.1 or 1.2, except when the Reliability Coordinator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.
R2	N/A	N/A	The Reliability Coordinator failed to designate Alternative Interpersonal Communication capability with one of the entities listed in Requirement R2, Parts 2.1 or 2.2.	The Reliability Coordinator failed to designate Alternative Interpersonal Communication capability with two or more of the entities listed in Requirement R2, Parts 2.1 or 2.2.
R3	N/A	N/A	The Transmission Operator failed to have Interpersonal Communication capability with one of the entities listed in Requirement R3, Parts 3.1, 3.2, 3.3, 3.4, 3.5, or 3.6, except when the Transmission Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.	The Transmission Operator failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R3, Parts 3.1, 3.2, 3.3, 3.4, 3.5, or 3.6, except when the Transmission Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.
R4	N/A	N/A	The Transmission Operator failed to designate Alternative Interpersonal Communication capability with one of the entities listed in Requirement R4, Parts 4.1, 4.2, 4.3, or 4.4.	The Transmission Operator failed to designate Alternative Interpersonal Communication capability with two or more of the entities listed in Requirement R4, Parts 4.1, 4.2, 4.3, or 4.4.

**Standard COM-001-2.1 — Communications**

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	The Balancing Authority failed to have Interpersonal Communication capability with one of the entities listed in Requirement R5, Parts 5.1, 5.2, 5.3, 5.4, or 5.5, except when the Balancing Authority detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.	The Balancing Authority failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R5, Parts 5.1, 5.2, 5.3, 5.4, or 5.5, except when the Balancing Authority detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.
R6	N/A	N/A	The Balancing Authority failed to designate Alternative Interpersonal Communication capability with one of the entities listed in Requirement R6, Parts 6.1, 6.2, or 6.3.	The Balancing Authority failed to designate Alternative Interpersonal Communication capability with two or more of the entities listed in Requirement R6, Parts 6.1, 6.2, or 6.3.
R7	N/A	N/A	The Distribution Provider failed to have Interpersonal Communication capability with one of the entities listed in Requirement R7, Parts 7.1 or 7.2, except when the Distribution Provider detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.	The Distribution Provider failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R7, Parts 7.1 or 7.2, except when the Distribution Provider detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.

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R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	N/A	N/A	The Generator Operator failed to have Interpersonal Communication capability with one of the entities listed in Requirement R8, Parts 8.1 or 8.2, except when a Generator Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.	The Generator Operator failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R8, Parts 8.1 or 8.2, except when a Generator Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.
R9	The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 2 hours and less than or equal to 4 hours upon an unsuccessful test.	The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 4 hours and less than or equal to 6 hours upon an unsuccessful test.	The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 6 hours and less than or equal to 8 hours upon an unsuccessful test.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to test the Alternative Interpersonal Communication capability once each calendar month.  OR The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 8 hours upon an unsuccessful test.



**Standard COM-001-2.1 — Communications**

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R10</b>	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 60 minutes but less than or equal to 70 minutes.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 70 minutes but less than or equal to 80 minutes.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 80 minutes but less than or equal to 90 minutes.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 90 minutes.
<b>R11</b>	N/A	N/A	N/A	The Distribution Provider or Generator Operator that detected a failure of its Interpersonal Communication capability failed to consult with each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of the Interpersonal Communication capability.

## E. Regional Differences

None identified.

## F. Associated Documents

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Regulatory Approval — Effective Date	New
1	April 6, 2007	Requirement 1, added the word “for” between “facilities” and “the exchange.”	Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to “1.1”	Errata
2	November 7, 2012	Adopted by Board of Trustees	Revised in accordance with SAR for Project 2006-06, Reliability Coordination (RC SDT). Replaced R1 with R1-R8; R2 replaced by R9; R3 included within new R1; R4 remains enforce pending Project 2007-02; R5 redundant with EOP-008-0, retiring R5 as redundant with EOP-008-0, R1; retiring R6, relates to ERO procedures; R10 & R11, new.
2	April 16, 2015	FERC Order issued approving COM-001-2	
2.1	August 25, 2015	Changed numbered parts under Requirement R6 to line up with the appropriate requirement.	Errata
2.1	November 13, 2015	FERC Letter Order approved errata to COM-001-2.1. Docket RD15-6-000	Errata

**Reliability Standard EOP-011-1**

### A. Introduction

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

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

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

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

### B. Requirements and Measures

- R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*
  - 1.1. Roles and responsibilities for activating the Operating Plan(s);
  - 1.2. Processes to prepare for and mitigate Emergencies including:
    - 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;
    - 1.2.2. Cancellation or recall of Transmission and generation outages;
    - 1.2.3. Transmission system reconfiguration;
    - 1.2.4. Redispatch of generation request;

- 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and
        - 1.2.6. Reliability impacts of extreme weather conditions.
  - M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.
  - R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*
    - 2.1. Roles and responsibilities for activating the Operating Plan(s);
    - 2.2. Processes to prepare for and mitigate Emergencies including:
      - 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;
      - 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;
      - 2.2.3. Managing generating resources in its Balancing Authority Area to address:
        - 2.2.3.1. capability and availability;
        - 2.2.3.2. fuel supply and inventory concerns;
        - 2.2.3.3. fuel switching capabilities; and
        - 2.2.3.4. environmental constraints.
      - 2.2.4. Public appeals for voluntary Load reductions;
      - 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;
      - 2.2.6. Reduction of internal utility energy use;
      - 2.2.7. Use of Interruptible Load, curtailable Load and demand response;
      - 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and
      - 2.2.9. Reliability impacts of extreme weather conditions.

- M2.** Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.
- R3.** The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- 3.1.** Within 30 calendar days of receipt, the Reliability Coordinator shall:
- 3.1.1.** Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;
  - 3.1.2.** Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and
  - 3.1.3.** Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.
- M3.** The Reliability Coordinator will have documentation, such as dated e-mails or other correspondences that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.
- R4.** Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*
- M4.** The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.
- R5.** Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

## EOP-011-1 Emergency Operations

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- M5.** Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators .
- R6.** Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. [*Violation Risk Factor: High*] [*Time Horizon: Real-Time Operations*]
- M6.** Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Evidence Retention

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

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

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

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

#### 1.3. Compliance Monitoring and Assessment Processes:

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

#### 1.4. Additional Compliance Information

None



**Table of Compliance Elements**

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

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

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

**EOP-011-1 Emergency Operations**

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

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

**Version History**

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	

### Attachment 1-EOP-011-1 Energy Emergency Alerts

#### Introduction

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

#### A. General Responsibilities

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

#### B. EEA Levels

##### Introduction

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

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

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

###### Circumstances:

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

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

###### Circumstances:

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

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

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

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

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

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

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

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

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

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

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

#### **Circumstances:**

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

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

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

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

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

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

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

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

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

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



### Guidelines and Technical Basis

#### **Rationale:**

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

#### **Rationale for R1:**

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

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

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

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

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

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

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

## Application Guidelines

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### **Rationale for R2:**

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

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

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

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

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

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

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

### **Rationale for R3:**

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

### **Rationale for Requirement R4:**

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

## Application Guidelines

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### Rationale for R5

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

### Rationale for Introduction

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

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

### Rationale for (2) Notification

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

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

## Application Guidelines

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### **Rationale for EEA 2:**

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

### **Rationale for EEA 3:**

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

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

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

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard EOP-011-1 — Emergency Operations**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
EOP-011-1	All	04/01/2017	

**Reliability Standard IRO-001-4**

### A. Introduction

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

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

See the Project 2014-03 [project page](#).

### B. Requirements and Measures

- R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*
- M1.** Each Reliability Coordinator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.
- R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator’s Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*
- M2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or

equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instructions, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator's Operating Instructions. If such a situation has not occurred, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

- R3.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*
- M3.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it informed its Reliability Coordinator of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R1.

### C. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

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

##### 1.2. Compliance Monitoring and Assessment Processes:

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

##### 1.3. Data Retention

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



provide other evidence to show that it was compliant for the full time period since the last audit.

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

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

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

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

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

None.

Table of Compliance Elements

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

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

**Version History**

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

## Standard IRO-001-4 Reliability Coordination - Responsibilities

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		Requirement R3 becomes the new R1 and R8 becomes the new R2 and R3.	
3	August 16, 2012	Adopted by Board of Trustees	Revised
4	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-001-4. Docket No. RM15-16-000, Order No. 817	

### Guidelines and Technical Basis

#### **Rationale:**

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

#### **Rationale for Applicability:**

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

#### **Rationale for Change from Reliability Directive to Operating Instruction:**

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

#### **Rationale for Requirements R2 and R3:**

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

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard IRO-001-4 — Reliability Coordination - Responsibilities and Authorities**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
IRO-001-4	All	04/01/2017	

**Reliability Standard IRO-002-4**

## A. Introduction

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

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

See the Project 2014-03 [project page](#).

## B. Requirements and Measures

- R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*
- M1.** Each Reliability Coordinator shall have and provide upon request, evidence that could include but is not limited to a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
- R2.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*
- M2.** Each Reliability Coordinator shall have and provide upon request evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
- R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any



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

- M3.** Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
- R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator’s operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
- M4.** The Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

## **C. Compliance**

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

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

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

#### **1.2. Compliance Monitoring and Assessment Processes:**

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

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

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation: The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R3 and Measures M1, M2, and M3.

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

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

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

**1.4. Additional Compliance Information**

None.

Table of Compliance Elements

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

**Standard IRO-002-4 — Reliability Coordination — Monitoring and Analysis**

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

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

**Version History**

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

**Standard IRO-002-4 — Reliability Coordination — Monitoring and Analysis**

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4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	

### Guidelines and Technical Basis

#### **Rationale:**

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

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

#### **Rationale for Requirements:**

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

#### **Rationale for R2:**

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

#### **Rationale for R4:**

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

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard IRO-002-4 — Reliability Coordination - Monitoring and Analysis**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
IRO-002-4	All	04/01/2017	



**Reliability Standard IRO-006-EAST-2**

## A. Introduction

1. **Title:** Transmission Loading Relief Procedure for the Eastern Interconnection
2. **Number:** IRO-006-EAST-2
3. **Purpose:** To coordinate action between Reliability Coordinators within the Eastern Interconnection when implementing transmission loading relief procedures (TLR) for the Eastern Interconnection to prevent or manage potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1. Reliability Coordinators in the Eastern Interconnection
5. **Effective Date:** See the Implementation Plan for IRO-006-EAST-2.

## B. Requirements and Measures

- R1. Each Reliability Coordinator that initiates the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance shall identify the TLR level and the congestion management actions to be implemented, and shall update this information at least every clock hour (except TLR-1) after initiation up to and including the hour when the TLR level has been identified as TLR Level 0.<sup>1</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]
- M1. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that at the time it initiated the Eastern Interconnection TLR procedure, and at least every clock hour after initiation up to and including the hour when the TLR level was identified as TLR Level 0, the Reliability Coordinator identified both the TLR Level and a list of congestion management actions to be implemented in accordance with Requirement R1.
- R2. Each Reliability Coordinator with a Sink Balancing Authority that must implement congestion management actions pursuant to the Eastern Interconnection TLR procedure shall, within 15 minutes of receiving the request from the issuing Reliability Coordinator, instruct the Sink Balancing Authority to implement the congestion management actions, subject to the following exception: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]
  - Should an assessment determine that one or more of the congestion management actions communicated will result in a reliability concern or will be

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<sup>1</sup> For more information on TLR levels, please see "Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels Reference Document."

ineffective, the Reliability Coordinator with a Sink Balancing Authority shall coordinate alternate congestion management actions with the issuing Reliability Coordinator.

- M2.** Each Reliability Coordinator with a Sink Balancing Authority that must implement congestion management actions pursuant to the Eastern Interconnection TLR procedure shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that within fifteen minutes of the receipt of a request, the Reliability Coordinator complied with the request by either 1) instructing the Sink Balancing Authority to implement the congestion management actions requested by the issuing Reliability Coordinator, or 2) instructing the Sink Balancing Authority to implement none or some of the communicated congestion management actions requested by the issuing Reliability Coordinator, and replacing the remainder with alternate congestion management actions if assessment showed that some or all of the requested congestion management actions would have resulted in a reliability concern or would have been ineffective in accordance with Requirement R2.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority:

“Compliance Enforcement Authority” means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

#### 1.2. Evidence Retention:

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

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

For Requirement R1 and Requirement R2, the Reliability Coordinator shall maintain evidence to show compliance with Requirement R1 and Requirement R2 for the past 12 months plus the current month.

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

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

#### 1.3. Compliance Monitoring and Enforcement Program

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

#### 1.4. Additional Compliance Information

None.

### Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R1.</b>	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for one clock hour during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for two clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for three clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for four or more clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.
<b>R2.</b>				The responding Reliability Coordinator did not, within 15 minutes of receiving a request, either 1) instruct the Sink Balancing Authority to implement all the requested congestion management actions, or 2) coordinate alternate congestion management actions with the issuing Reliability Coordinator,

				provided that: assessment showed that the actions replaced would have resulted in a reliability concern or would have been ineffective.
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**D. Regional Variances**

None.

**E. Associated Documents**

Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels Reference Document

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
1	November 4, 2010	Adopted by NERC Board of Trustees	
1	April 21, 2011	FERC approved IRO-006-EAST-1	
2	August 13, 2015	Adopted by NERC Board of Trustees	Revised to address the recommendations of the Project 2012-09 Interconnected Reliability Operations Five-Year Review Team.
2	December 4, 2015	FERC approved IRO-006-EAST-2. Docket No. RD14-14-001, RD15-3-001 & RD15-5-001	

### Rationale

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

**Rationale for recommendation to retire Requirement R1:** The standard drafting team (IRO SDT) agrees with the FYRT's assertion that IRO-006-EAST-1 Requirement R1 is redundant with IRO-008-1, Requirement R3, and IRO-009-1, Requirement R4, and that the requirements in IRO-008-1 and IRO-009-1 are results based and specify a reliability objective to be achieved. The IRO SDT further agrees with the FYRT's conclusion that IRO-006-EAST-1 Requirement R1 simply provides a list of actions to be taken without any parameters for their use.

**Rationale for recommendation to retire Requirement R3:** The IRO SDT agrees with the FYRT's determination that the intent of Requirement R3 is not to define a curtailment process when the IDC is compromised or unavailable. In the event of an Interchange Distribution Calculator (IDC) failure, Transmission Loading Relief (TLR) action would be very limited resulting in manual curtailments and other manual actions to preserve the reliability of the Bulk Electric System. The IRO SDT further agrees with the FYRT's assertion that Requirement R3 contains actions that are automatically generated via the IDC tool and sent to proper entities upon issuance of the TLR. This requirement should be removed from the standard, as it meets Paragraph 81 Criterion B1 – Administrative.

**Rationale for revisions to new Requirement R1 (previously Requirement R2):** The IRO SDT provided edits to improve clarity and to incorporate and simplify the sub-requirements into the main requirement.

**Rationale for Revisions to new Requirement R2 (previously Requirement R4):** The IRO SDT provided edits to improve clarity and to incorporate and simplify some of the bullets into the main requirement, and modified the remaining bullet to be a requirement instead of a passive statement.

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard IRO-006-EAST-2 — Transmission Loading Relief Procedure for the Eastern Interconnection**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
IRO-006-EAST-2	All	04/01/2016	



**Reliability Standard IRO-008-2**

## A. Introduction

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

## B. Requirements and Measures

- R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M1.** Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.
- R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M2.** Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

- R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- M3.** Each Reliability Coordinator shall have evidence that it notified impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.
- R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*
- M4.** Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.
- R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*
- M5.** Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.
- R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*
- M6.** Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its

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

## **C. Compliance**

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

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

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

#### **1.2. Compliance Monitoring and Assessment Processes**

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

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

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

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

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

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

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

**1.4. Additional Compliance Information**

None

**Table of Compliance Elements**

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

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

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



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

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

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

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

## D. Regional Variances

None

## E. Interpretations

None

## F. Associated Documents

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

## Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-008-2. Docket No. RM15-16-000. Order No. 817	

## **Guidelines and Technical Basis**

### **Rationale:**

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

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

### **Rationale for R1:**

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

### **Rationale for R2 and R3:**

Requirements added in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.

### **Rationale for R5 and R6:**

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

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard IRO-008-2 — Reliability Coordinator Operational Analyses and Real-time Assessments**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
IRO-008-2	All	04/01/2017	



**Reliability Standard IRO-009-2**

## A. Introduction

1. **Title:** Reliability Coordinator Actions to Operate Within IROLs
2. **Number:** IRO-009-2
3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate instances of exceeding Interconnection Reliability Operating Limits (IROLs).
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1. Reliability Coordinator.
5. **Effective Date:** See the Implementation Plan for IRO-009-2.

## B. Requirements and Measures

- R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including load shedding): *[Violation Risk Factor: Medium]* *[Time Horizon: Operations Planning or Same Day Operations]*
  - 1.1. That can be implemented in time to prevent the identified IROL exceedance.
  - 1.2. To mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's  $T_v$ .
- M1. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it has Operating Processes, Procedures, or Plans to address both preventing and mitigating the magnitude and duration of IROL exceedances in accordance with Requirement R1. This evidence shall include a list of any IROLs (and each associated  $T_v$ ) identified in advance, along with one or more dated Operating Processes, Procedures, or Plans that will be used.
- R2. Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High]* *[Time Horizon: Real-time Operations]*
- M2. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it initiated one or more Operating Processes, Procedures or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirements R1) in accordance with Requirement R2. This evidence could include, but is not

limited to, Operating Processes, Procedures, or Plans from Requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence.

- R3.** Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's  $T_v$ , as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
- M3.** Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it acted or directed others to act in accordance with Requirement R3. This evidence could include, but is not limited to, Operating Processes, Procedures, or Plans, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence.
- R4.** Each Reliability Coordinator shall operate to the most limiting IROL and  $T_v$  in instances where there is a difference in an IROL or its  $T_v$  between Reliability Coordinators that are responsible for that Facility (or group of Facilities). *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
- M4.** Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it operated to the most limiting IROL and  $T_v$  in instances where there was a difference in an IROL or its  $T_v$ . Such evidence could include, but is not limited to, dated computer printouts, dated operator logs, dated voice recordings, dated transcripts of voice recordings, or other equivalent evidence in accordance with Requirement R4.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority:

“Compliance Enforcement Authority” means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

#### 1.2. Evidence Retention:

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

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

The Reliability Coordinator shall retain evidence of Requirement R1; Requirement R2; Requirement R3; and Requirement R4 for a rolling 12 months.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records, and any reported IROL violations submitted since the last audit.

#### 1.3. Compliance Monitoring and Enforcement Program

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

#### 1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.				<p>An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to prevent that IROL exceedance (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to mitigate that IROL exceedance within the IROL’s T<sub>v</sub>. (Part 1.2).</p>
R2.				No Operating Processes, Procedures, or Plans were

				initiated that were intended to prevent a predicted IROL exceedance as identified in the Reliability Coordinator’s Real-time monitoring or Real-time Assessment.
<b>R3.</b>				Actual system conditions showed that there was an IROL exceedance in its Reliability Coordinator Area, and that the IROL exceedance was not mitigated within the IROL’s T <sub>v</sub> .
<b>R4.</b>				The most limiting IROL or its T <sub>v</sub> was not operated to between Reliability Coordinators that are responsible for the Facility (or group of Facilities) associated with the IROL.

**D. Regional Variances**

None.

**E. Associated Documents**

None.

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	FERC approved IRO-009-1	
2	August 13, 2015	Adopted by NERC Board of Trustees	Revised to address the recommendations of the Project 2012-09 Interconnected Reliability Operations Five-Year Review Team.
2	December 4, 2015	FERC approved IRO-009-2. Docket No. RD14-14-001, RD15-3-001 & RD15-5-001	

### Standard Attachments

None.

### Rationale

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

**Rationale for revisions to Requirement R1:** The standard drafting team (IRO SDT) revised this requirement by combining IRO-009-1 Requirements R1 and R2 to form one requirement with two subparts to make the requirements more concise, as both requirements contained similar language.

**Rationale for revisions to new Requirement R2 (previously Requirement R3):** The IRO SDT revised the language of this requirement to improve clarity as well as consistency with similar NERC Board of Trustees (Board) approved standards, such as, TOP standard revisions (TOP-001-3 R14); “IROL exceedance,” “Real-time monitoring,” and “Real-time Assessments.”

**Rationale for Revisions to Requirement R3 (previously Requirement R4):** The IRO SDT removed the term “without delay” from the requirement upon determining that the point of time at which the requirement is triggered is inherent in the requirement itself. The IRO SDT also revised the language of this requirement to improve clarity as well as consistency with similar Board approved standards, such as, TOP standard revisions (TOP-001-3 R14); “IROL exceedance,” “Real-time monitoring,” and “Real-time Assessments.”

**Rationale for revisions to Requirement R4 (previously Requirement R5):** The IRO SDT revised the language of this requirement for clarity as well as consistency with similar Board approved standards, such as TOP standard revisions (TOP-001-3 R18). The IRO SDT retained clarifying language to limit applicability to appropriate affected RCs.



**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard IRO-009-2 — Reliability Coordinator Actions to Operate Within IROLs**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
IRO-009-2	All	01/01/2016	

**Reliability Standard IRO-010-2**

### A. Introduction

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

See Implementation Plan.
6. **Background**

See Project 2014-03 [project page](#).

### B. Requirements

- R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*
  - 1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
  - 1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
  - 1.3. A periodicity for providing data.
  - 1.4. The deadline by which the respondent is to provide the indicated data.

- M1.** The Reliability Coordinator shall make available its dated, current, in force documented specification for data.
- R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. (*Violation Risk Factor: Low*) (*Time Horizon: Operations Planning*)
- M2.** The Reliability Coordinator shall make available evidence that it has distributed its data specification to entities that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.
- R3.** Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: (*Violation Risk Factor: Medium*) (*Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations*)
- 3.1** A mutually agreeable format
  - 3.2** A mutually agreeable process for resolving data conflicts
  - 3.3** A mutually agreeable security protocol
- M3.** The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

### C. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

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

##### 1.2 Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate

data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

**1.3. Data Retention**

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

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

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

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

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

**1.4. Additional Compliance Information**

None.

Table of Compliance Elements

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

**Standard IRO-010-2 — Reliability Coordinator Data Specification and Collection**

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

**Standard IRO-010-2 — Reliability Coordinator Data Specification and Collection**

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



**D. Regional Variances**

None

**E. Interpretations**

None

**F. Associated Documents**

None

**Version History**

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-010-2. Docket No. RM15-16-000	

### Guidelines and Technical Basis

#### **Rationale:**

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

#### **Rationale for Definitions:**

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

#### **Rationale for Applicability Changes:**

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

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

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

#### **Rationale:**

##### **Proposed Requirement R1, Part 1.1:**

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

##### **Proposed Requirement R1, Part 1.2:**

Is in response to NOPR paragraph 78 on relay data.

##### **Proposed Requirement R3, Part 3.3:**

## **Standard IRO-010-2 — Guidelines and Technical Basis**

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

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

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard IRO-010-2 — Reliability Coordinator Data Specification and Collection**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
IRO-010-2	R1.	01/01/2017	
IRO-010-2	1.1.	01/01/2017	
IRO-010-2	1.2.	01/01/2017	
IRO-010-2	1.3.	01/01/2017	
IRO-010-2	1.4.	01/01/2017	
IRO-010-2	R2.	01/01/2017	
IRO-010-2	R3.	04/01/2017	
IRO-010-2	3.1.	04/01/2017	
IRO-010-2	3.2.	04/01/2017	
IRO-010-2	3.3.	04/01/2017	

**Reliability Standard IRO-014-3**

## A. Introduction

1. **Title:** Coordination Among Reliability Coordinators
2. **Number:** IRO-014-3
3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not adversely impact other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.
4. **Applicability:**
  - 4.1. Reliability Coordinator
5. **Effective Date**

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

See Project 2014-03 [project page](#).

## B. Requirements and Measures

- R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations]*
  - 1.1. Criteria and processes for notifications.
  - 1.2. Energy and capacity shortages.
  - 1.3. Control of voltage, including the coordination of reactive resources.
  - 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.
  - 1.5. Provisions for periodic communications to support reliable operations.
- M1. Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that may impact adjacent Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements, and notes from periodic communications.
- R2. Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Same-Day Operations]*

## Standard IRO-014-3 — Coordination Among Reliability Coordinators

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- 2.1. Review and update annually with no more than 15 months between reviews.
  - 2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.
  - 2.3. Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.
- M2.** Each Reliability Coordinator shall have dated evidence that its Operating Procedures, Operating Processes, and Operating Plans that require one or more other Reliability Coordinators to take action were maintained as specified. This evidence may include but is not limited to dated documentation with confirmation of receipt, dated notice of acceptance or agreement to take specified actions, or dated electronic communications with confirmation of receipt and acceptance or agreement to take specified actions.
- R3.** Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*
- M3.** Each Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings, or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, notified other impacted Reliability Coordinators.
- R4.** Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*
- M4.** Each Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it operated as though an Emergency existed during each instance where Reliability Coordinators disagreed on the existence of an Emergency.
- R5.** Each Reliability Coordinator that Identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*
- M5.** Each Reliability Coordinator that identifies an Emergency in its Reliability Coordinator Area shall have evidence that it developed an action plan during those instances where impacted Reliability Coordinators disagreed on the existence of an Emergency. This evidence may include but is not limited to operator logs, voice recordings or

transcripts of voice recordings, electronic communications, or equivalent dated documentation.

- R6.** Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*
- M6.** Each impacted Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it implemented the action plan developed by the Reliability Coordinator who identifies the Emergency when Reliability Coordinators disagree on the existence of an Emergency unless such actions would have violated safety, equipment, regulatory, or statutory requirements.
- R7.** Each Reliability Coordinator shall assist Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High][Time Horizon: Real-time Operations]*
- M7.** Each Reliability Coordinator shall make available upon request, evidence that requested assistance was provided, if able, to requesting Reliability Coordinators unless such actions could not be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

## **C. Compliance**

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

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

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

#### **1.2. Compliance Monitoring and Assessment Processes:**

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



### **1.3. Data Retention**

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

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

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

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

### **1.4 Additional Compliance Information**

None

Table of Compliance Elements

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

**Standard IRO-014-3 — Coordination Among Reliability Coordinators**

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

**Standard IRO-014-3 — Coordination Among Reliability Coordinators**

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

**Standard IRO-014-3 — Coordination Among Reliability Coordinators**

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

### D. Regional Variances

None.

### E. Interpretations

None.

### F. Associated Documents

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

Version History

Version	Date	Action	Change Tracking
1	August 10, 2005	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash (–).”</li> <li>2. Hyphenated “30-day” when used as adjective.</li> <li>3. Changed standard header to be consistent with standard “Title.”</li> <li>4. Initial capped heading “Definitions of Terms Used in Standard.”</li> <li>5. Added “periods” to items where appropriate.</li> <li>6. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> <li>7. Lower cased all words that are not “defined” terms — drafting team, self-certification.</li> <li>8. Changed apostrophes to “smart” symbols.</li> <li>9. Added comma in all word strings “Procedures, Processes, or Plans,” etc.</li> <li>10. Added hyphens to “Reliability Coordinator-to-Reliability Coordinator” where used as adjective.</li> <li>11. Removed comma in item 2.1.2.</li> <li>12. Removed extra spaces between words where appropriate.</li> </ol>	January 20, 2006
1	February 7, 2006	Adopted by Board of Trustees	Revised
1	March 16, 2007	Approved by FERC	
2	August 4, 2011	<p>Revised per Project 2006-6; Revised existing requirements for clarity, retired R3 and R4 and incorporated requirements from IRO-015-1 and IRO-016-1 into this standard.</p> <p>Adopted by Board of Trustees</p>	Revised

## Standard IRO-014-3 — Coordination Among Reliability Coordinators

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3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved IRO-014-3. Docket No. RM15-16-000	



## **Guidelines and Technical Basis**

### **Rationale:**

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

### **Rationale for Terminology:**

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

### **Rationale for Requirement R7:**

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

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard IRO-014-3 — Coordination Among Reliability Coordinators**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
IRO-014-3	All	04/01/2017	

**Reliability Standard IRO-017-1**

## A. Introduction

1. **Title: Outage Coordination**
2. **Number: IRO-017-1**
3. **Purpose:** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.
4. **Applicability:**
  - 4.1. Reliability Coordinator
  - 4.2. Transmission Operator
  - 4.3. Balancing Authority
  - 4.4. Planning Coordinator
  - 4.5. Transmission Planner
5. **Effective Date:**

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

See Project 2014-03 [project page](#).

## B. Requirements and Measures

- R1.** Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
  - 1.1. Identify applicable roles and reporting responsibilities including:
    - 1.1.1. Development and communication of outage schedules.
    - 1.1.2. Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).
  - 1.2. Specify outage submission timing requirements.
  - 1.3. Define the process to evaluate the impact of Transmission and generation outages within its Wide Area.
  - 1.4. Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.
- M1.** Each Reliability Coordinator shall make available its dated, current, in force outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.

- R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator’s outage coordination process. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- M2.** Each Transmission Operator and Balancing Authority shall provide evidence upon request that it performed the functions specified in its Reliability Coordinator’s outage coordination process. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.
- R3.** Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M3.** Each Planning Coordinator and Transmission Planner shall provide evidence upon request showing that it provided its Planning Assessment to impacted Reliability Coordinators. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.
- R4.** Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M4.** Each Planning Coordinator, and Transmission Planner shall provide evidence upon request showing that it jointly developed solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

### C. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Process

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

##### 1.2. Compliance Monitoring and Assessment Processes

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

**1.3. Data Retention**

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

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

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

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

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

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

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

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

**1.4. Additional Compliance Information**

None.

Table of Compliance Elements

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

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



#### D. Regional Variances

None.

#### E. Interpretations

None.

#### F. Associated Documents

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

#### Version History

Version	Date	Action	Change Tracking
1	April 2014	New standard developed by Project 2014-03	New
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
1	November 19, 2015	FERC approved IRO-017-1. Docket No. RM15-16-000	

### Guidelines and Technical Basis

#### **Rationale:**

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

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

#### **Rationale for Time Horizon:**

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

#### **Rationale for R3:**

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

#### **Rationale for R4:**

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

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

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

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard IRO-017-1 — Outage Coordination**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
IRO-017-1	All	04/01/2017	

**Reliability Standard PRC-004-5**

## A. Introduction

1. **Title:** Protection System Misoperation Identification and Correction
2. **Number:** PRC-004-5
3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems for BES Elements, with the following exclusions:
      - 4.2.1.1 Non-protective functions that are embedded within a Protection System.
      - 4.2.1.2 Protective functions intended to operate as a control function during switching.<sup>1</sup>
      - 4.2.1.3 Special Protection Systems (SPS).
      - 4.2.1.4 Remedial Action Schemes (RAS).
      - 4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.
    - 4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.
    - 4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.
5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

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<sup>1</sup> For additional information and examples, see the “Non-Protective Functions” and “Control Functions” sections in the Application Guidelines.

## B. Requirements and Measures

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*
- 1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and
  - 1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and
  - 1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.
- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*
- 2.1** For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:
- 2.1.1** The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and
- 2.1.2** The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and
- 2.1.3** The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.
- 2.2** For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*
- The identification of the cause(s) of the Misoperation; or
  - A declaration that no cause was identified.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning]*
- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
  - Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.
- R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*



- M6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

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

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4. Additional Compliance Information**

None.

**D. Table of Compliance Elements**

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R1</b>	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation.  OR  The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation.  OR  The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R3</b>	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late.  OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R4</b>	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late.  OR  The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R5</b>	Operations Planning, Long-Term Planning	Medium	<p>The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.</p> <p>OR</p> <p>(See next page)</p>	<p>The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.</p> <p>OR</p> <p>(See next page)</p>	<p>The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.</p> <p>OR</p> <p>(See next page)</p>	<p>The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation.</p> <p>OR</p> <p>The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5.</p> <p>OR</p> <p>(See next page)</p>

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation.  OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.



**E. Regional Variances**

None.

**F. Interpretations**

None.

**G. Associated Documents**

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.<sup>2</sup>

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC’s Order approving the interpretation of R1 and R3 is effective as of September 26, 2011

<sup>2</sup> (<http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf>).

Version	Date	Action	Change Tracking
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "...and generator interconnection Facility..."
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5	May 7, 2015	Adopted by NERC Board of Trustees	Revision under Project 2008-02.2
5	November 19, 2015	FERC Letter Order issued approving PRC-004-5. Docket RD15-5-000	

## Guidelines and Technical Basis

### Introduction

This standard addresses the reliability issues identified in the letter<sup>3</sup> from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

“Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. ...Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization.”

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*<sup>4</sup>; July 2011.

“...a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry.”

The *State of Reliability 2014*<sup>5</sup> report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

### Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 “Transmission Protective Relay System Performance Measuring Methodology<sup>6</sup>.” Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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<sup>3</sup> (<http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf>).

<sup>4</sup> “2011 Risk Assessment of Reliability Performance.” NERC. ([http://www.nerc.com/files/2011\\_RARPR\\_FINAL.pdf](http://www.nerc.com/files/2011_RARPR_FINAL.pdf), July 2011). Pg. 3.

<sup>5</sup> “State of Reliability 2014.” NERC. (<http://www.nerc.com/pa/Stand/Pages/ReliabilityCoordinationProject20066.aspx>). May 2014. Pg. 18 of 106.

<sup>6</sup> “Transmission Protective Relay System Performance Measuring Methodology.” Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a “Protection System” is defined in the *Glossary of Terms Used in NERC Reliability Standards* (“NERC Glossary”) as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

**Composite Protection System** – *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element’s Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element’s multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element’s total complement of protection should be considered while evaluating an operation.

#### ***Composite Protection System – Line Example***

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

#### ***Composite Protection System – Transformer Example***

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

### **Composite Protection System – Generator Example**

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

### **Composite Protection System – Breaker Failure Example**

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker’s Composite Protection System. Considering breaker failure protection to be part of another Element’s Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the “Slow Trip” criteria of the Misoperation definition.

- An example of a correct operation of the breaker’s Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line’s Composite Protection System.
- An example of a correct operation of the breaker’s Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker’s Composite Protection System.
- An example of an “Unnecessary Trip – During Fault” is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

**Misoperation** – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

- 1. Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
- 2. Failure to Trip – Other Than Fault** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. **Slow Trip – During Fault** – *A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System.*
4. **Slow Trip – Other Than Fault** – *A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System.*
5. **Unnecessary Trip – During Fault** – *An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. **Unnecessary Trip – Other Than Fault** – *An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element’s total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a “Failure to Trip” or a “Slow Trip” does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

### ***Failure to Trip – During Fault***

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

**Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

**Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a “Failure to Trip – During Fault” Misoperation as long as another component of the transformer's Composite Protection System operated.

**Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

**Example 1d:** A failure of an overall differential relay to operate is not a “Failure to Trip – During Fault” Misoperation as long as another component such as a generator differential relay operated.

**Example 1e:** The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one “Failure to Trip – During Fault” Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – During Fault” category applies to the operation.

### ***Failure to Trip – Other Than Fault***

This category of Misoperation may have resulted in operator intervention. The “Failure to Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

**Example 2a:** A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

**Example 2b:** A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – Other Than Fault” category applies to the operation.

### ***Slow Trip – During Fault***

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

**Example 3a:** A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

**Example 3b:** A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

**Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

### ***Slow Trip – Other Than Fault***

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation



times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

**Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator's Composite Protection System, but not of the transmission line's Composite Protection System.

The "Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

### ***Unnecessary Trip – During Fault***

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

**Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

**Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.

**Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

### ***Unnecessary Trip – Other Than Fault***

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

**Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.

**Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.

**Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.

**Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

**Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

### **Special Cases**

Protection System operations for these cases would not be a Misoperation.

**Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

**Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

**Example 7c:** A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

**Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

## Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

## Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

**Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.

**Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

**Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

### **Extenuating Circumstances**

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: “In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties.” The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

### **Requirement Time Periods**

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

## Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

**Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device

owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*<sup>7</sup> which states:

“In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation.”

The following is an example of a condition that is not a Misoperation.

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<sup>7</sup> “Misoperations Report.” Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. ([http://www.nerc.com/docs/pc/psmtf/PSMTF\\_Report.pdf](http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf)). April 1, 2013. Pg. 37 of 40.

**Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

## Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

**Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

**Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

**Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

### Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.



The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

## Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

**Example R4a:** A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize

that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.<sup>8</sup>

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

**Example R4b:** A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.

**Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

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<sup>8</sup> NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013. ([http://www.nerc.com/docs/pc/psmtf/PSMTF\\_Report.pdf](http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf)). Figure 15: NERC Wide Misoperations by Cause Code. Pg. 22 of 40.

## Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

**Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

**Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

**Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.

A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

**Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.

Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

**Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.

**Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

**Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

**Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

**Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

## Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation)

through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

**Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

**Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.

CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

**Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.

CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

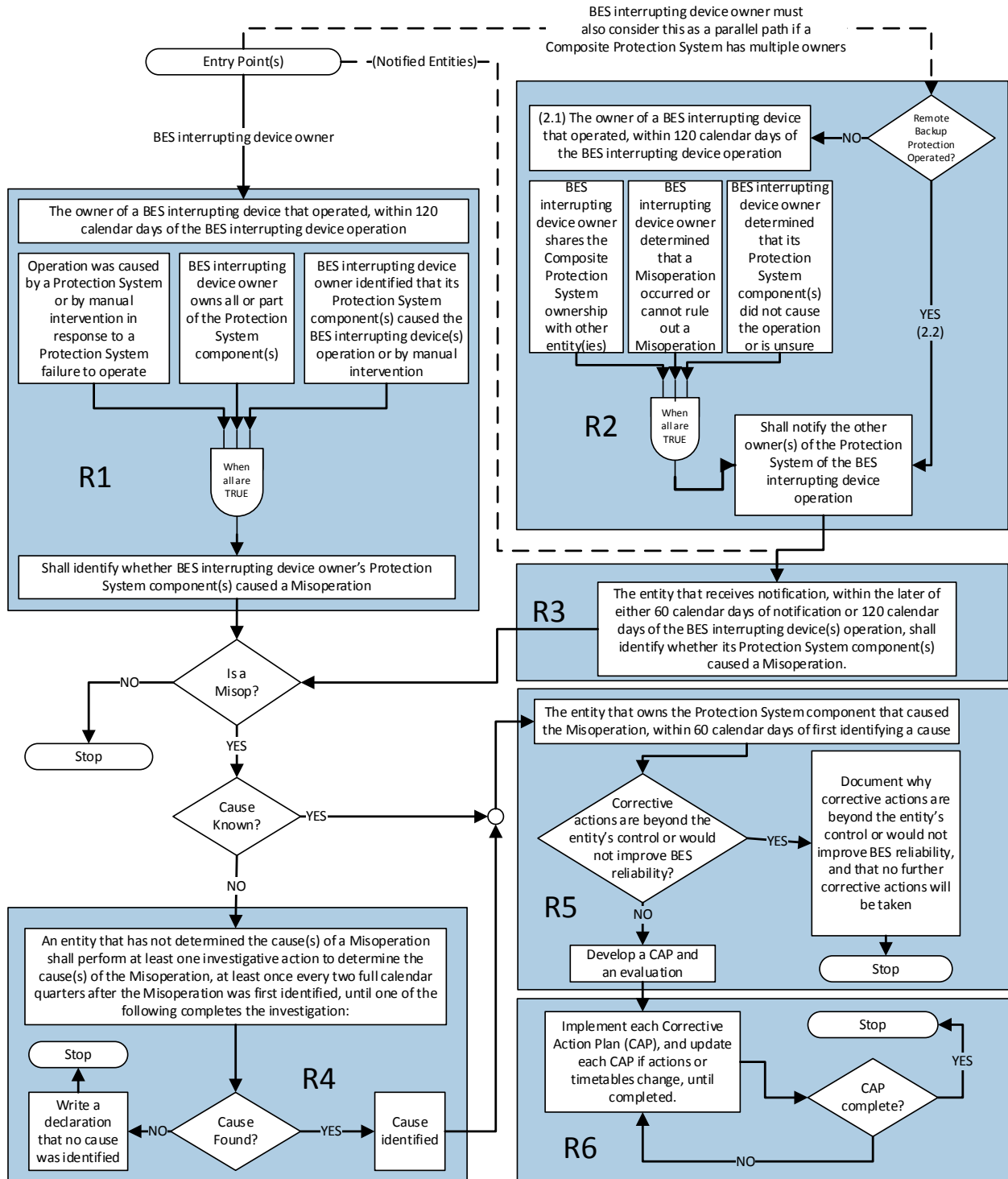
**Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.

CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

**Process Flow Chart:** Below is a graphical representation demonstrating the relationships between Requirements:





## Rationale

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

### Rationale for Introduction

The only revisions made to version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

### Rationale for Applicability

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for “common- mode failure” type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard PRC-004-5 — Protection System Misoperation Identification and Correction**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
PRC-004-5	All	04/02/2017	04/01/2017

**Reliability Standard PRC-005-6**

## A. Introduction

1. **Title:** Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
2. **Number:** PRC-005-6
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.
    - 4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, except for generators identified through Inclusion I4 of the BES definition, including:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

**4.2.6** Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:

**4.2.6.1** Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above.

**4.2.7** Automatic Reclosing<sup>1</sup>, including:

**4.2.7.1** Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.<sup>2</sup>

**4.2.7.2** Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

**4.2.7.3** Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

**5. Effective Date:** See the Implementation Plan for this standard.

**6. Definitions Used in this Standard:**

**Automatic Reclosing** – Includes the following Components:

- Reclosing relay
- Supervisory relay(s) or function(s) – relay(s) or function(s) that perform voltage and/or sync check functions that enable or disable operation of the reclosing relay
- Voltage sensing devices associated with the supervisory relay(s) or function(s)

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<sup>1</sup> Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

<sup>2</sup> The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

- Control circuitry associated with the reclosing relay or supervisory relay(s) or function(s)

**Sudden Pressure Relaying** – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

**Unresolved Maintenance Issue** – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**Segment** – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

**Component Type** –

- Any one of the five specific elements of a Protection System
- Any one of the four specific elements of Automatic Reclosing
- Any one of the two specific elements of Sudden Pressure Relaying

**Component** – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

**Countable Event** – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

## B. Requirements and Measures

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
  - 1.2.** Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.
- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented PSMP in accordance with Requirement R1.
- For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)
- For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5. (Part 1.2)
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the

time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5. *[Violation Risk Factor: High]*  
*[Time Horizon: Operations Planning]*

- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High]* *[Time Horizon: Operations Planning]*
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the PSMP for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium]* *[Time Horizon: Operations Planning]*
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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



## 1.2. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated PSMP, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

## 1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

**1.4. Additional Compliance Information**

None

### Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	<p>The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (Part 1.2).</p>	<p>The entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1).</p>
R2	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	<p>The entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p>

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,                              OR</li> <li>• Annually perform maintenance on the greater of 5% of the Segment population or 3 Components,                              OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul>
R3	For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

## D. Regional Variances

None.

## E. Interpretations

None.

## Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-6 Protection System Maintenance*, Protection System Maintenance and Testing Standard Drafting Team (July 2015)
2. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758*, NERC System Protection and Control Subcommittee (December 2013)
4. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – Supplemental Information to Support Project 2007-17.3: Protection System Maintenance and Testing* (October 31, 2014)

## Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	February 7, 2006	Adopted by NERC Board of Trustees	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> </ol> Changed “Timeframe” to “Time Frame” in item D, 1.2.
1	March 16, 2007	PRC-005-1 Approved by FERC. Docket No. RM06-16-000	

Version	Date	Action	Change Tracking
1a	February 17, 2011	Adopted by NERC Board of Trustees	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17
1a	September 26, 2011	Approved by FERC. Docket No. RD11-5-000	
1b	November 5, 2009	Adopted by NERC Board of Trustees	Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10
1b	February 3, 2012	FERC Order approving revised definition of “Protection System”	Per footnote 8 of FERC’s order, the definition of “Protection System” supersedes interpretation “b” of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013) <i>See N. Amer. Elec. Reliability Corp., 138 FERC ¶ 61,095 (February 3, 2012).</i>
1b	February 3, 2012	PRC-005-1b Approved by FERC. Docket No. RM10-5-000	
1.1b	May 9, 2012	Adopted by NERC Board of Trustees	Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility
1.1b	September 19, 2013	PRC-005-1.1b Approved by FERC. Docket No. RM12-16-000	
2	November 7, 2012	Adopted by NERC Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0

Version	Date	Action	Change Tracking
2	October 17, 2013	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section. (no change to standard version number)
2	December 19, 2013	PRC-005-2 Approved by FERC. Docket No. RM13-7-000	
2	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number)
2(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
2(i)	May 29, 2015	PRC-005-2(i) Approved by FERC. Docket No. RD15-3-000	
2(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No. 758 to include Automatic Reclosing in maintenance programs



Version	Date	Action	Change Tracking
3	February 12, 2014	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved errata changes to correct capitalization of certain defined terms within the definitions of “Unresolved Maintenance Issue” and “Protection System Maintenance Program”. The changes will be reflected in the definitions section of PRC-005-3 for “Unresolved Maintenance Issue” and in the NERC Glossary of Terms for “Protection System Maintenance Program”. (no change to standard version number)
3	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number)
3	January 22, 2015	PRC-005-3 Approved by FERC. Docket No. RM14-8-000	
3(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
3(i)	May 29, 2015	PRC-005-3(i) Approved by FERC. Docket No. RD15-3-000	
3(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 13, 2014	Adopted by NERC Board of Trustees	Added Sudden Pressure Relaying in response to FERC Order No. 758
4	Sept 17, 2015	PRC-005-4 Approved by FERC. Docket No. RM15-9-000	

Version	Date	Action	Change Tracking
5	May 7, 2015	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources.
6	November 5, 2015	Adopted by NERC Board of Trustees	Revised to add supervisory relays, the voltage sensing devices, and the associated control circuitry to Automatic Reclosing in accordance with the directives in FERC Order 803.
6	December 18, 2015	FERC Letter Order approving PRC-005-6. Docket No. RD16-2-000.	

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval <sup>3</sup>	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul>
Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul>	12 Calendar Years	Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>

<sup>3</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval <sup>3</sup>	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul>	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).  Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).  Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul>	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

<b>Table 1-3</b> <b>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays</b> <b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b>		
<b>Component Attributes</b>	<b>Maximum Maintenance Interval</b>	<b>Maintenance Activities</b>
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with ac measurements that are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>
	18 Calendar Months	Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul>

<p style="text-align: center;"><b>Table 1-4(a)</b>  <b>Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries</b>  <b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b></p> <p style="text-align: center;">Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.



Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>
	18 Calendar Months	Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul>

<p style="text-align: center;"><b>Table 1-4(b)</b>  <b>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries</b>  <b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b></p> <p style="text-align: center;">Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>
	18 Calendar Months	Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul>

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

<b>Table 1-4(f)</b> <b>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems</b>		
<b>Component Attributes</b>	<b>Maximum Maintenance Interval</b>	<b>Maintenance Activities</b>
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

<b>Table 1-5</b> <b>Component Type - Control Circuitry Associated With Protective Functions</b> <b>Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5)</b> <b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.</b>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.



<b>Table 2 – Alarming Paths and Monitoring</b> In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.  Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring:  The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	<p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate.</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul>
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>	12 Calendar Years	<p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• AC measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> </ul>	12 Calendar Years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

<b>Table 3</b> <b>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>		
<b>Component Attributes</b>	<b>Maximum Maintenance Interval</b>	<b>Maintenance Activities</b>
<ul style="list-style-type: none"> <li>Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

<p align="center"><b>Table 4-1</b></p> <p align="center"><b>Maintenance Activities and Intervals for Automatic Reclosing Components</b></p> <p align="center"><b>Component Type – Reclosing and Supervisory Relay</b></p> <p><b>Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.</b></p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
<p>Any unmonitored reclosing relay or supervisory relay not having all the monitoring attributes of a category below.</p>	<p>6 Calendar Years</p>	<p>Verify that settings are as specified.</p> <p>For non-microprocessor reclosing or supervisory relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> <p>For microprocessor reclosing or supervisory relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul> <p>For microprocessor supervisory relays:</p> <ul style="list-style-type: none"> <li>• Verify acceptable measurement of power system input values.</li> </ul>
<ul style="list-style-type: none"> <li>• Monitored microprocessor reclosing relay or supervisory relay with the following: Internal self-diagnosis and alarming (See Table 2).</li> <li>• Alarming for power supply failure (See Table 2).</li> </ul> <p>For supervisory relay:</p> <ul style="list-style-type: none"> <li>• Voltage waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul>	<p>12 Calendar Years</p>	<p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul> <p>For supervisory relays:</p> <ul style="list-style-type: none"> <li>• Verify acceptable measurement of power system input values.</li> </ul>

<p style="text-align: center;"><b>Table 4-1</b>  <b>Maintenance Activities and Intervals for Automatic Reclosing Components</b>  <b>Component Type – Reclosing and Supervisory Relay</b></p>		
<p><b>Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.</b></p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
<p>Monitored microprocessor reclosing relay or supervisory relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> <p>For supervisory relay:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> </ul>	<p>12 Calendar Years</p>	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</p>

Table 4-2(a)

Maintenance Activities and Intervals for Automatic Reclosing Components

Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that are NOT an Integral Part of an RAS

Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

**Table 4-2(b)**

**Maintenance Activities and Intervals for Automatic Reclosing Components**

**Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that ARE an Integral Part of an RAS**

**Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.**

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

<p align="center"><b>Table 4-3</b></p> <p align="center"><b>Maintenance Activities and Intervals for Automatic Reclosing Components</b></p> <p align="center"><b>Component Type – Voltage Sensing Devices Associated with Supervisory Relays</b></p> <p align="center"><b>Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-3, the Components only need to be tested once during a distinct maintenance interval.</b></p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that voltage signal values are provided to the supervisory relays.
Voltage sensing devices that are connected to microprocessor supervisory relays with ac measurements that are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure. (See Table 2)	No periodic maintenance specified	None.



<p style="text-align: center;"><b>Table 5</b>  <b>Maintenance Activities and Intervals for Sudden Pressure Relaying</b></p>		
<p style="text-align: center;"><b>Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.</b></p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

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**PRC-005 — Attachment A**

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

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**Rationale:**

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

**Rationale for revisions to Automatic Reclosing:**

To address directives from FERC Order No. 803 addressing Automatic Reclosing, the definition for Automatic Reclosing was revised to add supervisory relays, the associated voltage sensing devices, and the associated control circuitry.

**Rationale for revisions to Component Type:**

With the revision of the definition of Automatic Reclosing, there are four specific elements of this definition, rather than two as stated in the prior version.

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard PRC-005-6 — Protection System, Automatic Reclosing, and Sudden Pressure Relaying**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
PRC-005-6	All	01/01/2016	

**Reliability Standard PRC-010-1**

## A. Introduction

1. **Title: Undervoltage Load Shedding**
2. **Number: PRC-010-1**
3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Planning Coordinator
    - 4.1.2 Transmission Planner
    - 4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.
5. **Background:**

PRC-010-1 – Undervoltage Load Shedding is a consolidation and revision of the following Reliability Standards:

- PRC-010-0 – Assessment of the Design and Effectiveness of UVLS Program
- PRC-020-1 – Under-Voltage Load Shedding Program Database
- PRC-021-1 – Under-Voltage Load Shedding Program Data
- PRC-022-1 – Under-Voltage Load Shedding Program Performance

The UVLS Standard Drafting Team (or drafting team) developed the revised PRC-010-1 to meet the following objectives:

- Address the FERC directive in Order No. 693, Paragraph 1509 to modify PRC-010-0 to require an integrated and coordinated approach to all protection systems.
- Replace the applicability to and involvement of the Regional Reliability Organization (RRO) in PRC-020-1 and PRC-021-1.
- Consolidate the UVLS-related standards into one comprehensive standard (similar to the construct of FERC-approved PRC-006-1– Automatic Underfrequency Load Shedding).
- Clearly identify and separate centrally controlled undervoltage-based load shedding due to the reliability requirements needed for this type of load shedding as compared to other UVLS systems.
- Create a single results-based standard that addresses current reliability issues associated with UVLS.

## B. Requirements and Measures

- R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program’s specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.
  - 1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.
- M1.** Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.
- R2.** Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- M2.** Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.
- R3.** Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 3.1.** The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.
  - 3.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.
- M3.** Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.
- R4.** Each Planning Coordinator or Transmission Planner shall, within 12 calendar

## PRC-010-1 – Undervoltage Load Shedding

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months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate whether its UVLS Program resolved the undervoltage issues associated with the event.

*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- M4.** Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program.
- R5.** Each Planning Coordinator or Transmission Planner that identifies deficiencies in its UVLS Program during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- M5.** Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.
- R6.** Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M6.** Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.
- R7.** Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M7.** Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.
- R8.** Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M8.** Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.



## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Evidence Retention

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

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

The applicable entity shall retain documentation as evidence for six calendar years.

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

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

#### 1.3. Compliance Monitoring and Assessment Processes:

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

#### 1.4. Additional Compliance Information

None

**Table of Compliance Elements**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program’s effectiveness and subsequently provide the UVLS Program’s specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2.  OR  The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.

**PRC-010-1 – Undervoltage Load Shedding**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event.  OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

**PRC-010-1 – Undervoltage Load Shedding**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days.  OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days.  OR The applicable entity failed to update the database in accordance with Requirement R6.

**PRC-010-1 – Undervoltage Load Shedding**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	<p>The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule.</p> <p>OR</p> <p>The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.</p>	<p>The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.</p>	<p>The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.</p>	<p>The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule.</p> <p>OR</p> <p>The applicable entity failed to provide data in accordance with Requirement R7.</p>
R8	Operations Planning	Lower	<p>The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.</p>	<p>The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.</p>	<p>The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.</p>	<p>The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days.</p> <p>OR</p> <p>The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.</p>

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

### Guidelines and Technical Basis

#### Introduction

PRC-010-1 is a single, comprehensive standard that addresses the same reliability principles outlined in its legacy standards, PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1. The standard also addresses a FERC directive from Order No. 693, Paragraph 1509. This paragraph directs NERC to develop a modification to PRC-010-0 that requires an integrated and coordinated approach to all protection systems, including generators and transmission lines, generators' low voltage ride-through capabilities, and underfrequency load shedding (UFLS) and UVLS programs.

Since FERC-approved PRC-006-1 – Automatic Underfrequency Load Shedding was developed under a similar construct of combining existing standards and addressing a FERC Order No. 693 directive, the drafting team looked to this standard as a guide. With the understanding that UVLS and UFLS systems have fundamental differences, the drafting team adopted PRC-006-1's industry-vetted reliability principles and language as applicable to UVLS Programs.

The drafting team's established purpose for PRC-010-1 is to clearly define the responsibilities of applicable entities to pursue an integrated and coordinated approach to the design, evaluation, and reliable operation of UVLS Programs. Since the need for and design of UVLS Programs is unique to each system preservation footprint, the intent of the standard is to provide a framework of reliability requirements for such programs to which each individual entity can apply its program's specific considerations and characteristics. The drafting team emphasizes that PRC-010-1 does not require a mandatory UVLS Program, nor does this standard address the need to have a UVLS Program. PRC-010-1 applies only after an entity has determined the need for a UVLS Program as a result of its own planning studies.

The drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

The design and characteristics of a centrally controlled undervoltage-based load shedding system are commensurate with a Special Protection System (SPS) or Remedial Action Scheme (RAS), therefore, the drafting team maintains that this type of load shedding should be covered by SPS-or-RAS-related Reliability Standards. Therefore, PRC-010-1 introduces a new Glossary of Terms Used in NERC Reliability Standards term, UVLS Program, to establish the applicability of PRC-010-1 to automatic load shedding programs consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Undervoltage-based load shedding that does not have such an impact as determined by the Planning Coordinator or Transmission Planner is not included. It is further noted that this term excludes centrally controlled undervoltage-based load shedding.

Subsequently, since the current Glossary of Terms Used in NERC Reliability Standards definition of Special Protection System excludes UVLS, concurrent Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) will adjust the definition to exclude only UVLS Programs as defined above and therefore include centrally controlled undervoltage-

## Guidelines and Technical Basis

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based load shedding. Of note, the drafting team for Project 2010-05.2 is proposing to change the term from Special Protection System to Remedial Action Scheme. Accordingly, PRC-010-1 uses the term Remedial Action Scheme instead of Special Protection System. In the current inventory of NERC Reliability Standards, there is one instance of the term undervoltage load shedding program, which is in NUC-001-2.1. Project 2012-13–Nuclear Plant Interface Coordination has adjusted the language of this reference in proposed NUC-001-3 to eliminate any potential confusion of a lowercase usage of a defined term. Likewise, future projects containing standards that feature variations of the term (e.g., undervoltage load shedding system) will also be advised to consider the newly defined term.

Requirements of the revised Reliability Standard PRC-010-1 meet the following objectives:

- Evaluate a UVLS Program’s effectiveness prior to implementation, including the program’s coordination with other protection systems and generator voltage ride-through capabilities.
- Adhere to UVLS Program specifications and implementation schedule.
- Perform periodic assessment and performance analysis of UVLS Programs and resolve identified deficiencies.
- Maintain and share UVLS Program data.

Also of note, Project 2009-03 – Emergency Operations is proposing EOP-011-1, which, as part of the overall revisions, retires specific requirements from EOP-003-2 – Load Shedding Plans to eliminate identified redundancy between PRC-010-1 and EOP-003-2. In addition, the UVLS drafting team’s intention is for PRC-004 to address Misoperations of UVLS Programs that are intended to trip one or more BES Elements. A change to make these types of UVLS Programs explicitly applicable to PRC-004 will be addressed once PRC-004-3 – Protection System Misoperation Identification and Correction is completed under Project 2010-05.1 – Misoperations (Phase 1 of Protection Systems).



## Guidelines and Technical Basis

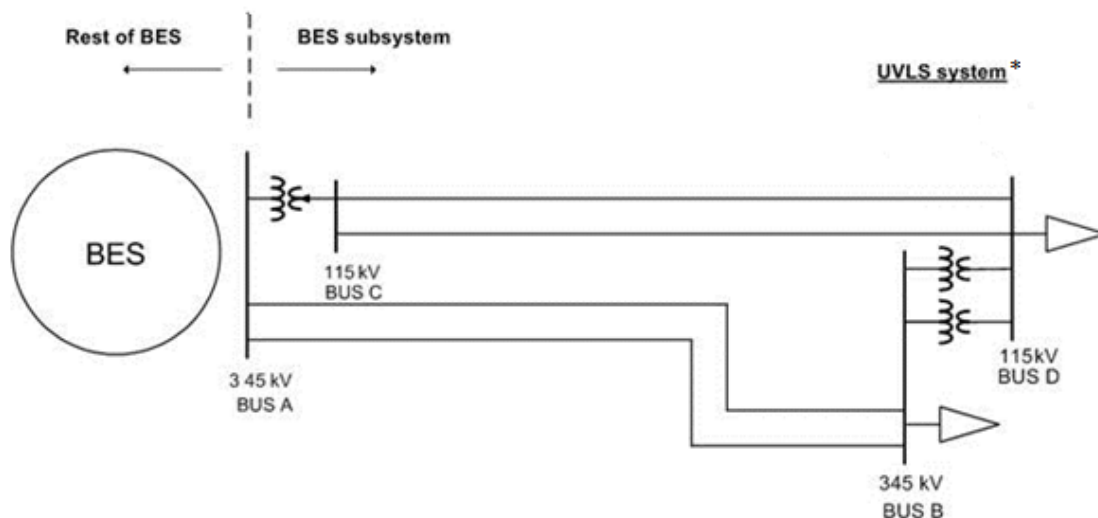
### Guidelines for UVLS Program Definition

The definition for the term UVLS Program includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The definition for the term UVLS Program excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a RAS, wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard is to only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the BES. An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Below is an example of a BES subsystem for which UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between bus A and bus B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading involving the BES, UVLS system (installed at either, or both, bus B and D) used to mitigate this case would not fall under the definition of a UVLS Program. However, if this same UVLS system would be used to mitigate Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.



\*UVLS systems may be installed at either, or both, bus B and D

**High Level Requirement Overview**

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

**Guidelines for Requirement R1:**

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static var systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators’ voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

## Guidelines and Technical Basis

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Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

Examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

### Guidelines for Requirement R2:

Once a Planning Coordinator or Transmission Planner has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, the location at which load needs to be shed, etc. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks.

## **Guidelines and Technical Basis**

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The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the misoperation of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

### **Guidelines for Requirement R3:**

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment should be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment supplements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

## **Guidelines and Technical Basis**

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With respect to situations in which a material change to system and topology or operating conditions would necessitate a comprehensive assessment of the UVLS Program, it is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

### **Guidelines for Requirement R4:**

The goal of the assessment required in Requirement R4 is to evaluate whether the UVLS Program resolved the undervoltage issues for an event that occurred on the system. It is expected that the assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event shall be performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5.

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

### **Guidelines for Requirement R5:**

Requirement R5 promotes the prudent correction of an identified problem during assessment evaluations of each UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate.
- At least once every 60 months. The default time frame of 60 months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated.

## **Guidelines and Technical Basis**

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Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, the drafting team believes that within three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The “within three calendar months” time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP’s associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

### **Guidelines for Requirements R6–R8**

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop remedial action plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted

## Guidelines and Technical Basis

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- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS, and RAS.

Additionally, the UVLS Program database should be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well-accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

## Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	March 16, 2007	Approved by FERC	
0	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
0	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

**Guidelines and Technical Basis**

1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Completed revision, merged and updated PRC-010-0, PRC-020-1, PRC- 021-1, and PRC-022-1.
1	November 19, 2015	FERC approved PRC-010-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	

**Rationale:**

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

**Rationale for Applicability**

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase “Planning Coordinator or Transmission Planner” provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

**Rationale for R1**



## **Guidelines and Technical Basis**

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In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

### **Rationale for R2**

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

### **Rationale for R3**

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

### **Rationale for R4**

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission

## **Guidelines and Technical Basis**

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Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

### **Rationale for R5**

If program deficiencies are identified during an assessment of a UVLS Program performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

### **Rationale for R6**

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

### **Rationale for R7**

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

### **Rationale for R8**

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard PRC-010-1 — Undervoltage Load Shedding**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
PRC-010-1	All	04/01/2017	04/01/2017

**Reliability Standard PRC-010-2**

## A. Introduction

1. **Title:** Undervoltage Load Shedding
2. **Number:** PRC-010-2
3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Planning Coordinator.
    - 4.1.2 Transmission Planner.
    - 4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.
5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

## B. Requirements and Measures

- R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program’s specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
  - 1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.
  - 1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.
- M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.
- R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- M2.** Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.
- R3.** Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
  - 3.1.** The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.
  - 3.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.
- M3.** Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.
- R4.** Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
  - 4.1.** Whether its UVLS Program resolved the undervoltage issues associated with the event, and
  - 4.2.** The performance (i.e., operation and non-operation) of the UVLS Program equipment.
- M4.** Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.
- R5.** Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- M5.** Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

- R6.** Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M6.** Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.
- R7.** Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M7.** Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.
- R8.** Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M8.** Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Evidence Retention

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

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified

below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

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

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

**1.3. Compliance Monitoring and Assessment Processes**

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

**1.4. Additional Compliance Information**

None.



### Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program’s effectiveness and subsequently provide the UVLS Program’s specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	<p>The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2.</p> <p>OR</p> <p>The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.</p>	<p>The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.</p>
R3	Long-term Planning	Medium	N/A	N/A	N/A	<p>The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.</p>

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event.  OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days.  OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days.  OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	<p>The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule.</p> <p>OR</p> <p>The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.</p>	<p>The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.</p>	<p>The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.</p>	<p>The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule.</p> <p>OR</p> <p>The applicable entity failed to provide data in accordance with Requirement R7.</p>

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days.  OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

**Version History**

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2	May 7, 2015	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.
2	November 19, 2015	FERC Letter Order issued approving PRC-010-2. Docket RD15-5-000	



## Guidelines and Technical Basis

### Introduction

The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

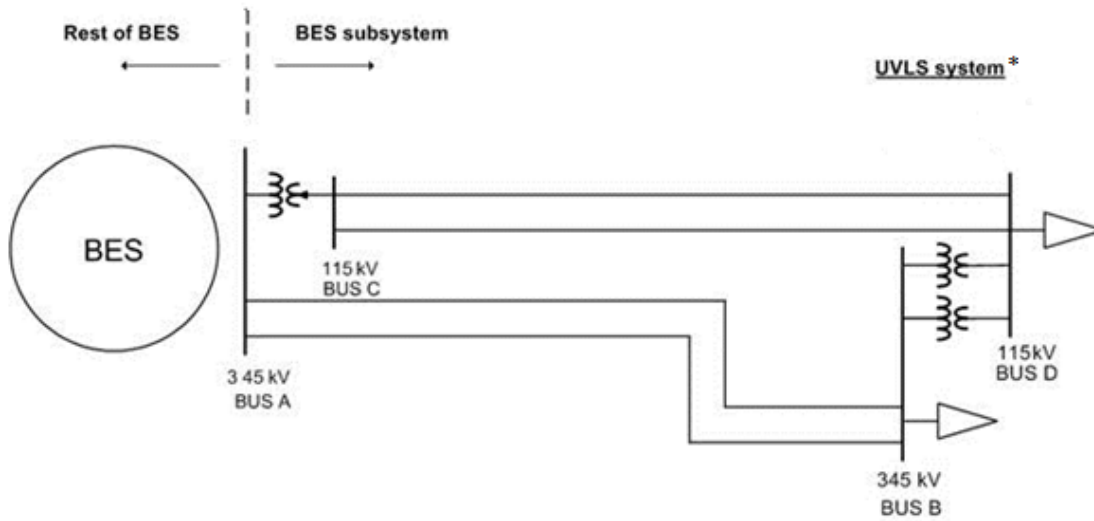
### Guidelines for UVLS Program Definition

The definition for the term, “Undervoltage Load Shedding Program” or “UVLS Program” includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between buses A and B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading, a UVLS system (installed at either, or both, bus B and D) used to mitigate this Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.



\*UVLS systems may be installed at either, or both, bus B and D

**Figure 1: UVLS Subsystem**

### Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview						
Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

### Guidelines for Requirement R1

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system

performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

## **Guidelines for Requirement R2**

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

**CAP Example 1** - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

**CAP Example 2** - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the Misoperation<sup>1</sup> of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

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<sup>1</sup> Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. [http://www.nerc.com/pa/RAPA/ProtectionSystemMisoperations/PRC-004-3%20Section%201600%20Data%20Request\\_20140729.pdf](http://www.nerc.com/pa/RAPA/ProtectionSystemMisoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf).

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

### **Guidelines for Requirement R3**

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment is required to be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change<sup>2</sup> to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment complements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

### **Guidelines for Requirement R4**

After a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event is performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are

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<sup>2</sup> It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.<sup>3</sup>

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

### **Guidelines for Requirement R5**

Requirement R5 promotes the prudent correction of an identified problem during the assessment of a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The “within three

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<sup>3</sup> Id.

calendar months” time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP’s associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

### **Guidelines for Requirements R6–R8**

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted
- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS), and RAS

Additionally, the UVLS Program database is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well- accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the

directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

## Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

### Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)<sup>4,5</sup> to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)<sup>6</sup> standard drafting team (“drafting team”). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.<sup>7</sup> This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

### Purpose of Standard Revision

#### 1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC [Order No. 693](#),<sup>8</sup> Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that “requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators’ low voltage ride through capabilities, and UFLS and UVLS programs.” In addition, [The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations](#)<sup>9</sup> (“August 14 Blackout Report”) showed that proper coordination would have mitigated effects if UVLS was used as a tool.

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<sup>4</sup> ([http://www.nerc.com/\\_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding](http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding)).

<sup>5</sup> Adopted by the NERC Board of Trustees on November 14, 2014.

<sup>6</sup> (<http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx>).

<sup>7</sup> Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. ([http://www.nerc.com/pa/Stand/Pages/Project2010-05\\_Protection\\_System\\_Misoperations.aspx](http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx)).

<sup>8</sup> ([http://www.nerc.com/docs/docs/ferc/order\\_693.pdf](http://www.nerc.com/docs/docs/ferc/order_693.pdf)).

<sup>9</sup> (<http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf>).



Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 [Technical Review of UVLS-Related Standards](#)<sup>10</sup> to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

## **2) UVLS programs are not mandatory—is compliance for an optional tool necessary?**

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term “UVLS Program,” which limits the standard’s applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.<sup>11</sup>

## **Coordination with Project 2009-03 Emergency Operations**

### **3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?**

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),<sup>12</sup> Requirements R2, R4, and R7 as being more properly covered by Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and

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<sup>10</sup> ([http://www.nerc.com/docs/pc/spctf/PRC-010\\_022%20Report\\_Approved\\_20101208.pdf](http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf)).

<sup>11</sup> The term “UVLS Program” used herein was adopted by the NERC Board of Trustees on November 14, 2014.

<sup>12</sup> (<http://www.nerc.com/layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans>).

consolidate EOP-001-2.1b (*Emergency Operations Planning*),<sup>13</sup> EOP-002-3 (Capacity and Energy Emergencies),<sup>14</sup> and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2 requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)<sup>15</sup> and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

## “UVLS Program” Definition

### 4) Why is the introduction of the new defined term “UVLS Program” necessary?

The drafting team found it necessary to introduce the term “UVLS Program” for inclusion in the [Glossary of Terms Used in NERC Reliability Standards](#)<sup>16</sup> (“NERC Glossary”) because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: “automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.”

The definition excludes locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of “local” or “wide-area” varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading “Guidelines for UVLS Program Definition.”

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and

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<sup>13</sup> (<http://www.nerc.com/layers/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning>).

<sup>14</sup> (<http://www.nerc.com/layers/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies>).

<sup>15</sup> (<http://www.nerc.com/layers/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations>).

<sup>16</sup> ([http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary\\_of\\_Terms.pdf](http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf)).

PRC-010-2 Guidelines and Technical Basis section under the heading “Guidelines for UVLS Program Definition” for further discussion.

**5) If the definition excludes certain types of UVLS, does this preclude an “integrated” approach (FERC Order No. 693, Paragraph 1509)?**

The defined term “UVLS Program” clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an “integrated” approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

**6) Where will centrally controlled undervoltage-based load shedding be covered?**

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term “UVLS Program,” which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of “Special Protection System” excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of “Special Protection System” into the single term “Remedial Action Scheme.”<sup>17</sup> The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term “UVLS Program” and the conforming revision to the term “Remedial Action Scheme” explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of “Remedial Action Scheme” will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of “Remedial Action Scheme” and “UVLS Program,” the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

**7) Is the term “UVLS Program” inclusive of a collection of independent UVLS relays?**

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be “[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage

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<sup>17</sup> Adopted by the NERC Board of Trustees on November 14, 2014.

instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.”

## **Applicability**

### **8) What is meant by the phrase “Planning Coordinator or Transmission Planner”?**

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase “Planning Coordinator or Transmission Planner” provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: “Each Planning Coordinator or Transmission Planner *that is developing a UVLS Program* shall . . .” This language provides clarity that the applicable entity would be the one that is developing the program.

### **9) Why is the Transmission Operator not included?**

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),<sup>18</sup> Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

### **10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?**

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term “UVLS Program.” The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner

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<sup>18</sup> <http://www.nerc.com/layers/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination>.

would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

## **Requirements R1, R3, R4, and R5**

### **11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?**

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

### **12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?**

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion) to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

### **13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions— isn't this unduly burdensome?**

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS

threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

**14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?**

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

**Requirements R6, R7, and R8**

**15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?**

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)<sup>19</sup> and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

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<sup>19</sup> (<http://www.nerc.com/layers/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis>).

**16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?<sup>20</sup>**

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)<sup>21,22</sup> data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

**Rationale**

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

**Rationale for Applicability**

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

**Rationale for R1**

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning

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<sup>20</sup> Refer to Standards Independent Expert Review Project (IERP). ([http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards\\_Independent\\_Experts\\_Review\\_Project\\_Report-SOTC\\_and\\_Board.pdf](http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf)).

<sup>21</sup> (<http://www.nerc.com/layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding>).

<sup>22</sup> Adopted by the NERC Board of Trustees on November 14, 2014.

Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

#### **Rationale for R2**

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

#### **Rationale for R3**

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

#### **Rationale for R4**

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators,



and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

**Rationale for R5**

If program deficiencies are identified during an assessment performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team’s knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

**Rationale for R6**

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

**Rationale for R7**

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

**Rationale for R8**

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard PRC-010-2 — Undervoltage Load Shedding**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
PRC-010-2	All	04/02/2017	

**Reliability Standard TOP-001-3**

## A. Introduction

1. **Title: Transmission Operations**
2. **Number: TOP-001-3**
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
  - 4.1. Balancing Authority
  - 4.2. Transmission Operator
  - 4.3. Generator Operator
  - 4.4. Distribution Provider
5. **Effective Date:**

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

See Project 2014-03 [project page](#).

## B. Requirements and Measures

- R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*
- M1.** Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
- R2.** Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*
- M2.** Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

- R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*
- M3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.
- R4.** Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*
- M4.** Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.
- R5.** Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*
- M5.** Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and

provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

- R6.** Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*
- M6.** Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.
- R7.** Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*
- M7.** Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.
- R8.** Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*
- M8.** Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings,

electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

- R9.** Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*
- M9.** Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.
- R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*
- 10.1.** Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and
  - 10.2.** Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.
- M10.** Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized status, voltages, and flow data for Facilities and the status of Special Protection Systems as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.
- R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*
- M11.** Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be

used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

- R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T<sub>v</sub>. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
- M12.** Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T<sub>v</sub>. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.
- R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
- M13.** Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.
- R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
- M14.** Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.
- R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*
- M15.** Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.
- R16.** Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control



equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

- M16.** Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
- R17.** Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*
- M17.** Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
- R18.** Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*
- M18.** Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.
- R19.** Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*
- M19.** Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.
- R20.** Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

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

## **C. Compliance**

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

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

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

#### **1.2. Compliance Monitoring and Assessment Processes**

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

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

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

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

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

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

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

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

**1.4. Additional Compliance Information**

None.

**Table of Compliance Elements**

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

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

**Standard TOP-001-3 — Transmission Operations**

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

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

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



**Standard TOP-001-3 — Transmission Operations**

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

**Standard TOP-001-3 — Transmission Operations**

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

**Standard TOP-001-3 — Transmission Operations**

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

## D. Regional Variances

None.

## E. Interpretations

None.

## F. Associated Documents

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

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

## Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	

### Rationale:

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

### Rationale for Requirement R3:

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

### Rationale for Requirement R10:

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

### **Rationale for Requirement R13:**

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

### **Rationale for Requirement R14:**

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

### **Rationale for Requirements R16 and R17:**

In response to IERP Report recommendation 3 on authority.

### **Rationale for Requirement R18:**

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

### **Rationale for Requirements R19 and R20:**

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

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard TOP-001-3 — Transmission Operations**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
TOP-001-3	All	04/01/2017	

**Reliability Standard TOP-002-4**



## A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-4**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
  - 4.1. Transmission Operator
  - 4.2. Balancing Authority
5. **Effective Date:**

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

See Project 2014-03 [project page](#).

## B. Requirements and Measures

- R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M1.** Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.
- R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M2.** Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.
- R3.** Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M3.** Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

- R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- 4.1** Expected generation resource commitment and dispatch
  - 4.2** Interchange scheduling
  - 4.3** Demand patterns
  - 4.4** Capacity and energy reserve requirements, including deliverability capability
- M4.** Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include but is not limited to dated operator logs or e-mail records.
- R5.** Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- M5.** Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs or e-mail records.
- R6.** Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- M6.** Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or e-mail records.
- R7.** Each Balancing Authority shall provide its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- M7.** Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or e-mail records.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Compliance Monitoring and Assessment Processes

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

#### 1.3. Data Retention

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

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

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

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

#### 1.4. Additional Compliance Information

None.

**Table of Compliance Elements**

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

**Standard TOP-002-4 — Operations Planning**

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

**Standard TOP-002-4 — Operations Planning**

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

### D. Regional Variances

None.

### E. Interpretations

None.

### F. Associated Documents

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

## Version History

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



## Standard TOP-002-4 — Operations Planning

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3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised
4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. Order No. 817.	

### Guidelines and Technical Basis

#### **Rationale:**

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

#### **Rationale for Definitions:**

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

#### **Rationale for R1:**

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

#### **Rationale for R2:**

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

#### **Rationale for R3:**

Changes in response to IERP recommendation

#### **Rationale for R4 and R5:**

These Requirements were added to address IERP recommendations

#### **Rationale for R6 and R7:**

Added in response to SW Outage Report recommendation 1

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard TOP-002-4 — Operations Planning**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
TOP-002-4	All	04/01/2017	

**Reliability Standard TOP-003-3**

## A. Introduction

1. **Title: Operational Reliability Data**
2. **Number: TOP-003-3**
3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities.
4. **Applicability:**
  - 4.1. Transmission Operator
  - 4.2. Balancing Authority
  - 4.3. Generator Owner
  - 4.4. Generator Operator
  - 4.5. Load-Serving Entity
  - 4.6. Transmission Owner
  - 4.7. Distribution Provider
5. **Effective Date:**

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

See Project 2014-03 [project page](#).

## B. Requirements and Measures

- R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*
  - 1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.
  - 1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
  - 1.3. A periodicity for providing data.
  - 1.4. The deadline by which the respondent is to provide the indicated data.
- M1. Each Transmission Operator shall make available its dated, current, in force documented specification for data.

- R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*
- 2.1.** A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.
  - 2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
  - 2.3.** A periodicity for providing data.
  - 2.4.** The deadline by which the respondent is to provide the indicated data.
- M2.** Each Balancing Authority shall make available its dated, current, in force documented specification for data.
- R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*
- M3.** Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have data required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.
- R4.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority’s analysis functions and Real-time monitoring. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*
- M4.** Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have data required by the Balancing Authority’s analysis functions and Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.
- R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*
- 5.1.** A mutually agreeable format
  - 5.2.** A mutually agreeable process for resolving data conflicts
  - 5.3.** A mutually agreeable security protocol

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

## **C. Compliance**

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

#### **1.1. Compliance Monitoring Process**

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

#### **1.2. Compliance Monitoring and Assessment Processes**

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

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

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

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

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

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

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

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

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

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

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

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

**1.4. Additional Compliance Information**

None.



**Table of Compliance Elements**

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

**Standard TOP-003-3 — Operational Reliability Data**

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

**Standard TOP-003-3 — Operational Reliability Data**

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

**Standard TOP-003-3 — Operational Reliability Data**

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

#### D. Regional Variances

None.

#### E. Interpretations

None.

#### F. Associated Documents

None.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	

### Guidelines and Technical Basis

#### **Rationale:**

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

#### **Rationale for Definitions:**

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

#### **Rationale for R1:**

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

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

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

#### **Rationale for R5:**

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

\* FOR INFORMATIONAL PURPOSES ONLY \*

**Enforcement Dates: Standard TOP-003-3 — Operational Reliability Data**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
TOP-003-3	R1.	01/01/2017	
TOP-003-3	1.1.	01/01/2017	
TOP-003-3	1.2.	01/01/2017	
TOP-003-3	1.3.	01/01/2017	
TOP-003-3	1.4.	01/01/2017	
TOP-003-3	R2.	01/01/2017	
TOP-003-3	2.1.	01/01/2017	
TOP-003-3	2.2.	01/01/2017	
TOP-003-3	2.3.	01/01/2017	
TOP-003-3	2.4.	01/01/2017	
TOP-003-3	R3.	01/01/2017	
TOP-003-3	R4.	01/01/2017	
TOP-003-3	R5.	04/01/2017	
TOP-003-3	5.1.	04/01/2017	
TOP-003-3	5.2.	04/01/2017	
TOP-003-3	5.3.	04/01/2017	

**Reliability Standard VAR-001-4.1**



## A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-4.1
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
  - 4.1. Transmission Operators
  - 4.2. Generator Operators within the Western Interconnection (for the WECC Variance)
5. **Effective Date:**
  - 5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements and Measures

- R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operational Planning]*
- 1.1.** Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.
- M1.** The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.
- For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.
- R2.** Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Planning]*
- M2.** Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operational planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.
- R3.** Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Planning]*
- M3.** Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.
- R4.** The Transmission Operator shall specify the criteria that will exempt generators from: 1) following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 4.1** If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.
- M4.** Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt from: 1) following a voltage or Reactive Power schedule, 2) from having its

automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

- R5.** Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- 5.1.** The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).
- 5.2.** The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
- 5.3.** The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.
- M5.** The Transmission Operator shall have evidence of a documented voltage or Reactive Power Schedule (which is either a range or a target value with an associated tolerance band).
- For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.
- For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.
- R6.** After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M6.** The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

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

#### 1.2. Evidence Retention:

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

The Transmission Operator shall retain evidence for Measures 1 through 6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

#### 1.3. Compliance Monitoring and Assessment Processes:

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

#### 1.4. Additional Compliance Information:

None

**Table of Compliance Elements**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operational Planning	High	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	Real-time Operations, Same-day Operations, and Operational Planning	High	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	Real-time Operations, Same-day Operations, and Operational Planning	High	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Lower	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5	Operations Planning	Medium	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	<p>The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators.</p> <p>Or</p> <p>The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the</p>

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
<b>R6</b>	<b>Operations Planning</b>	<b>Lower</b>	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

## D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

### Requirements

- E.A.13** Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*
- A voltage set point with a voltage tolerance band and a specified period.
  - An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
  - A voltage band for a specified period.
- E.A.14** Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its Area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*
- The generator terminals.
  - The high side of the generator step-up transformer.
  - The point of interconnection.
  - A location designated by mutual agreement between the Transmission Operator and Generator Operator.
- E.A.15** Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*
- E.A.16** Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- E.A.17** Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*



**E.A.18** Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the Automatic Voltage Regulators (AVR) to manage MVar loading: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

**E.A.18.1.** Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

**E.A.18.2.** Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

**Measures<sup>1</sup>**

**M.E.A.13** Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.

**M.E.A.14** The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.

**M.E.A.15** Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.

**M.E.A.16** The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

**M.E.A.17** The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

**M.E.A.18** If the Generator Operator uses outside control loops to manage MVar loading, the Generator Operator shall have and provide upon request, evidence that it met the control loop specifications in sub-parts E.A.18.1 through E.A.18.2. Design specifications with identified agreed-upon control loops, system reports, or other dated documentation are acceptable as evidence.

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<sup>1</sup> The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.

### Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>E.A.13</b>	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
<b>E.A.14</b>	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
<b>E.A.15</b>	The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	than 25% of the voltage schedules.	less than 50% of the voltage schedules.	the voltage schedules.	
<b>E.A.16</b>	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
<b>E.A.17</b>	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>E.A.18</b>	N/A	The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

**E. Interpretations**

None.

**F. Associated Documents**

None.

### Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

#### **Rationale:**

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

#### **Rationale for R1:**

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on "established limits" and "sufficient reactive resources", and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) and 2) System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

#### **Rationale for R2:**

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

#### **Rationale for R3:**

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

### **Rationale for R4:**

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

### **Rationale for R5:**

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage Schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

### **Rationale for R6:**

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

## Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added "Generator Owners" and "Generator Operators" to Applicability section.	Errata
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January, 10 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added "or" to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Enforcement Dates: Standard VAR-001-4.1 — Voltage and Reactive Control**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Enforcement Date</b>	<b>Inactive Date</b>
VAR-001-4.1	All	11/13/2015	



**Exhibit B**  
**Updated *Glossary of Terms Used in NERC Reliability Standards***

# Glossary of Terms Used in NERC Reliability Standards

Updated January 29, 2016

## Introduction:

This Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through January 29, 2016.

This reference is divided into two sections, and each section is organized in alphabetical order. The first section identifies all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the second section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards. (WECC, NPCC and RF are the only Regions that have definitions approved by the NERC Board of Trustees. If other Regions develop definitions for approved Regional Standards using a NERC-approved standards development process, those definitions will be added to the Regional Definitions section of this glossary.)

Most of the terms identified in this glossary were adopted as part of the development of NERC's initial set of reliability standards, called the "Version 0" standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC's Reliability Standards Development Process, and added to this glossary following board adoption, with the "FERC approved" date added following a final Order approving the definition.

Immediately under each term is a link to the archive for the development of that term.

- Definitions that have been adopted by the NERC Board of Trustees but have not been approved by FERC, or FERC has not approved but has directed be modified, are shaded in blue.
- Definitions that have been remanded or retired are shaded in orange.
- Definitions that have been approved by FERC are white.

Any comments regarding this glossary should be reported to the following:

[sarcomm@nerc.com](mailto:sarcomm@nerc.com) with "Glossary Comment" in the subject line.

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Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Adequacy <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adjacent Balancing Authority <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact <a href="#">[Archive]</a>		2/7/2006	3/16/2007	The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
Adverse Reliability Impact <a href="#">[Archive]</a>		8/4/2011		The impact of an event that results in Bulk Electric System instability or Cascading.
After the Fact <a href="#">[Archive]</a>	ATF	10/29/2008	12/17/2009	A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A contract or arrangement, either written or verbal and sometimes enforceable by law.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Alternative Interpersonal Communication <a href="#">[Archive]</a>		11/7/2012	4/16/2015 (Becomes effective 10/1/2015)	Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation.
Altitude Correction Factor <a href="#">[Archive]</a>		2/7/2006	3/16/2007	A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. ( <i>From FERC order 888-A.</i> )
Anti-Aliasing Filter <a href="#">[Archive]</a>		2/8/2005	3/16/2007	An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error <a href="#">[Archive]</a>	ACE	2/8/2005	3/16/2007 (Becomes inactive 3/31/14)	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Area Control Error <a href="#">[Archive]</a>	ACE	12/19/2012	10/16/2013 (Becomes effective 4/1/2014)	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.
Area Interchange Methodology <a href="#">[Archive]</a>		08/22/2008	11/24/2009	The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.
Arranged Interchange <a href="#">[Archive]</a>		5/2/2006	3/16/2007	The state where the Interchange Authority has received the Interchange information (initial or revised).
Arranged Interchange <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	The state where a Request for Interchange (initial or revised) has been submitted for approval.
Attaining Balancing Authority <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.



Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Automatic Generation Control <a href="#">[Archive]</a>	AGC	2/8/2005	3/16/2007	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.
Available Flowgate Capability <a href="#">[Archive]</a>	AFC	08/22/2008	11/24/2009	A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.
Available Transfer Capability <a href="#">[Archive]</a>	ATC	2/8/2005	3/16/2007	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.
Available Transfer Capability <a href="#">[Archive]</a>	ATC	08/22/2008	11/24/2009	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Available Transfer Capability Implementation Document <a href="#">[Archive]</a>	ATCID	08/22/2008	11/24/2009	A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.
ATC Path <a href="#">[Archive]</a>		08/22/2008	Not approved; Modification directed 11/24/09	Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path <sup>1</sup> .

<sup>1</sup> See 18 CFR 37.6(b)(1)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Balancing Authority <a href="#">[Archive]</a>	BA	2/8/2005	3/16/2007	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Balancing Contingency Event <a href="#">[Archive]</a>		11/5/2015		Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less. A. Sudden loss of generation: <ul style="list-style-type: none"> <li>a. Due to                             <ul style="list-style-type: none"> <li>i. unit tripping, or</li> <li>ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity’s System, or</li> <li>iii. sudden unplanned outage of transmission Facility;</li> </ul> </li> <li>b. And, that causes an unexpected change to the responsible entity’s ACE;</li> </ul> B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection. C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity’s ACE.
Base Load <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The minimum amount of electric power delivered or required over a given period at a constant rate.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
BES Cyber Asset <a href="#">[Archive]</a>		11/26/2012	11/22/2013 (Becomes effective 4/1/2016)	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems. (A Cyber Asset is not a BES Cyber Asset if, for 30 consecutive calendar days or less, it is directly connected to a network within an ESP, a Cyber Asset within an ESP, or to a BES Cyber Asset, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.)
BES Cyber Asset <a href="#">[Archive]</a>	BCA	2/12/2015	1/21/2016 (effective 7/1/2016)	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.
BES Cyber System <a href="#">[Archive]</a>		11/26/2012	11/22/2013 (Becomes effective 4/1/2016)	One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
BES Cyber System Information <a href="#">[Archive]</a>		11/26/2012	11/22/2013 (Becomes effective 4/1/2016)	Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BES Cyber System Information may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System.
Blackstart Capability Plan <a href="#">[Archive]</a>		2/8/2005 Will be retired when EOP-005-2 becomes enforceable on (7/1/13)	3/16/2007	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Blackstart Resource <a href="#">[Archive]</a>		8/5/2009	3/17/2011	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan.
Blackstart Resource <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan.
Block Dispatch <a href="#">[Archive]</a>		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable “blocks,” each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or “must-run” status).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System <a href="#">[Archive]</a>	BES	2/8/2005	3/16/2007 (Becomes inactive on 6/30/2014)	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.



Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System <sup>2</sup> <a href="#">[Archive]</a>	BES	01/18/2012	6/14/2013 (Replaced by BES definition FERC approved 3/20/2014)	<p>Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.</p> <p><b>Inclusions:</b></p> <ul style="list-style-type: none"> <li>• <b>I1</b> - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3.</li> <li>• <b>I2</b> - Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.</li> <li>• <b>I3</b> - Blackstart Resources identified in the Transmission Operator’s restoration plan.</li> <li>• <b>I4</b> - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.</li> </ul>

<sup>2</sup> FERC issued an order on April 18, 2013 approving the revised definition with an effective date of July 1, 2013. On June 14, 2013, FERC granted NERC’s request to extend the effective date of the revised definition of the Bulk Electric System to July 1, 2014.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System <b>(Continued)</b>	BES			<p><b>I5</b> –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.</p> <p><b>Exclusions:</b></p> <ul style="list-style-type: none"> <li>• <b>E1</b> - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:               <ul style="list-style-type: none"> <li>a) Only serves Load. Or,</li> <li>b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,</li> <li>c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).</li> </ul> </li> </ul> <p>Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.</p>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System <b>(Continued)</b>	BES			<ul style="list-style-type: none"> <li>• <b>E2</b> - A generating unit or multiple generating units on the customer’s side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.</li> <li>• <b>E3</b> - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN’s emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:</li> </ul>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System <b>(Continued)</b>	BES			<p>a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);</p> <p>b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and</p> <p>c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).</p> <ul style="list-style-type: none"> <li>• <b>E4</b> – Reactive Power devices owned and operated by the retail customer solely for its own use. Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.</li> </ul>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
<p>Bulk Electric System</p> <p><a href="#">[Archive]</a></p>	<p>BES</p>	<p>11/21/2013</p>	<p>3/20/14 (Becomes effective 7/1/2014)</p> <p>(Please see the Implementation Plan for Phase 2 Compliance obligations.)</p>	<p>Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.</p> <p><b>Inclusions:</b></p> <ul style="list-style-type: none"> <li>• <b>I1</b> - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.</li> <li>• <b>I2</b> - Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:             <ul style="list-style-type: none"> <li>a) Gross individual nameplate rating greater than 20 MVA. Or,</li> <li>b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.</li> </ul> </li> <li>• <b>I3</b> - Blackstart Resources identified in the Transmission Operator’s restoration plan.</li> <li>• <b>I4</b> - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above.</li> </ul> <p>Thus, the facilities designated as BES are:</p>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System <b>(Continued)</b>	BES			<ul style="list-style-type: none"> <li>a) The individual resources, and</li> <li>b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.</li> </ul> <ul style="list-style-type: none"> <li>• <b>I5</b> –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.</li> </ul> <p><b>Exclusions:</b></p> <ul style="list-style-type: none"> <li>• <b>E1</b> - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:               <ul style="list-style-type: none"> <li>a) Only serves Load. Or,</li> <li>b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,</li> <li>c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).</li> </ul> </li> </ul>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System <b>(Continued)</b>	BES			<p>Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.</p> <p>Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.</p> <ul style="list-style-type: none"> <li>• <b>E2</b> - A generating unit or multiple generating units on the customer’s side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.</li> <li>• <b>E3</b> - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN’s emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:             <ul style="list-style-type: none"> <li>a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail</li> </ul> </li> </ul>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System <b>(Continued)</b>	BES			<p>generation greater than 75 MVA (gross nameplate rating);</p> <p>b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and</p> <p>c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).</p> <ul style="list-style-type: none"> <li>• <b>E4</b> – Reactive Power devices installed for the sole benefit of a retail customer(s).</li> </ul> <p>Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.</p>
Bulk-Power System <a href="#">[Archive]</a>		5/9/2013	7/9/2013	<p>A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.</p>



Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk-Power System <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	Bulk-Power System: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.)
Burden <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Business Practices <a href="#">[Archive]</a>		8/22/2008	Not approved; Modification directed 11/24/2009	Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.
Bus-tie Breaker <a href="#">[Archive]</a>		8/4/2011	10/17/2013 (Becomes effective 1/1/2015)	A circuit breaker that is positioned to connect two individual substation bus configurations.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Capacity Benefit Margin <a href="#">[Archive]</a>	CBM	2/8/2005	3/16/2007	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider’s system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Capacity Benefit Margin Implementation Document <a href="#">[Archive]</a>	CBMID	11/13/2008	11/24/2009	A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A capacity emergency exists when a Balancing Authority Area’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Cascading <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
Cascading Outages <a href="#">[Archive]</a>		11/1/2006 Withdrawn 2/12/2008	FERC Remanded 12/27/2007	<del>The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.</del>
CIP Exceptional Circumstance <a href="#">[Archive]</a>		11/26/12	11/22/2013 (Becomes effective 4/1/2016)	A situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or BES reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.
CIP Senior Manager <a href="#">[Archive]</a>		11/26/12	11/22/2013 (Becomes effective 4/1/2016)	A single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC CIP Standards, CIP-002 through CIP-011.
Clock Hour <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Compliance Monitor <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Composite Confirmed Interchange <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
Composite Protection System <a href="#">[Archive]</a>		8/14/2014	5/13/2015 (Becomes effective 7/1/2016)	The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.
Confirmed Interchange <a href="#">[Archive]</a>		5/2/2006	3/16/2007	The state where the Interchange Authority has verified the Arranged Interchange.
Confirmed Interchange <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	The state where no party has denied and all required parties have approved the Arranged Interchange.
Congestion Management Report <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Consequential Load Loss <a href="#">[Archive]</a>		8/4/2011	10/17/2013 (Becomes effective 1/1/2015)	All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Constrained Facility <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contingency <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Event Recovery Period <a href="#">[Archive]</a>		11/5/2015		A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.
Contingency Reserve <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Contingency Reserve <a href="#">[Archive]</a>				The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority: <ul style="list-style-type: none"> <li>• is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.</li> <li>• is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.</li> </ul>
Contingency Reserve Restoration Period <a href="#">[Archive]</a>		11/5/2015		A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.
Contract Path <a href="#">[Archive]</a>		2/8/2005	3/16/2007	An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Control Center <a href="#">[Archive]</a>		11/26/12	11/22/13 (Becomes effective 4/1/16)	One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.
Control Performance Standard <a href="#">[Archive]</a>	CPS	2/8/2005	3/16/2007	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan <a href="#">[Archive]</a>		2/7/2006	3/16/2007	A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path <a href="#">[Archive]</a>		5/2/2006	3/16/2007	A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Critical Assets <a href="#">[Archive]</a>		5/2/2006	1/18/2008 (Becomes inactive 3/31/2016)	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Critical Cyber Assets <a href="#">[Archive]</a>		5/2/2006	1/18/2008 (Becomes inactive 3/31/2016)	Cyber Assets essential to the reliable operation of Critical Assets.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Curtailment <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets <a href="#">[Archive]</a>		5/2/2006	1/18/2008 (Becomes inactive 3/31/2016)	Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Assets <a href="#">[Archive]</a>		11/26/12	11/22/2013 (Becomes effective 4/1/2016)	Programmable electronic devices, including the hardware, software, and data in those devices.
Cyber Security Incident <a href="#">[Archive]</a>		5/2/2006	1/18/2008 (Becomes inactive 3/31/2016)	Any malicious act or suspicious event that: <ul style="list-style-type: none"> <li>• Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or,</li> <li>• Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.</li> </ul>
Cyber Security Incident <a href="#">[Archive]</a>		11/26/12	11/22/2013 (Becomes effective 4/1/2016)	A malicious act or suspicious event that: <ul style="list-style-type: none"> <li>• Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or,</li> <li>• Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.</li> </ul>



Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Delayed Fault Clearing <a href="#">[Archive]</a>		11/1/2006	12/27/2007	Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
Demand <a href="#">[Archive]</a>		2/8/2005	3/16/2007	<ol style="list-style-type: none"> <li>1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.</li> <li>2. The rate at which energy is being used by the customer.</li> </ol>
Demand-Side Management <a href="#">[Archive]</a>	DSM	2/8/2005	3/16/2007	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Demand-Side Management <a href="#">[Archive]</a>	DSM	5/6/2014	2/19/2015 (Becomes effective 7/1/16)	All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.
Dial-up Connectivity <a href="#">[Archive]</a>		11/26/12	11/22/2013 (Becomes effective 4/1/2016)	A data communication link that is established when the communication equipment dials a phone number and negotiates a connection with the equipment on the other end of the link.
Direct Control Load Management <a href="#">[Archive]</a>	DCLM	2/8/2005	3/16/2007	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Dispatch Order <a href="#">[Archive]</a>		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.
Dispersed Load by Substations <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor <a href="#">[Archive]</a>	DF	2/8/2005	3/16/2007	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).
Distribution Provider <a href="#">[Archive]</a>	DP	2/8/2005	3/16/2007	Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Distribution Provider <a href="#">[Archive]</a>	DP	11/5/2015	1/21/2016 (effective 7/1/2016)	Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Disturbance <a href="#">[Archive]</a>		2/8/2005	3/16/2007	<ol style="list-style-type: none"> <li>1. An unplanned event that produces an abnormal system condition.</li> <li>2. Any perturbation to the electric system.</li> <li>3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.</li> </ol>
Disturbance Control Standard <a href="#">[Archive]</a>	DCS	2/8/2005	3/16/2007	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.
Disturbance Monitoring Equipment <a href="#">[Archive]</a>	DME	8/2/2006	3/16/2007	<p>Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders<sup>3</sup>:</p> <ul style="list-style-type: none"> <li>• Sequence of event recorders which record equipment response to the event</li> <li>• Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays.</li> <li>• Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions</li> </ul>

<sup>3</sup> Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Dynamic Interchange Schedule or Dynamic Schedule <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Dynamic Interchange Schedule or Dynamic Schedule <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A time-varying energy transfer that is updated in Real-time and included in the Scheduled Net Interchange (NIS) term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
Dynamic Transfer <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Economic Dispatch <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electronic Access Control or Monitoring Systems <a href="#">[Archive]</a>	EACMS	11/26/12	11/22/2013 (Becomes effective 4/1/2016)	Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems.
Electronic Access Point <a href="#">[Archive]</a>	EAP	11/26/12	11/22/2013 (Becomes effective 4/1/2016)	A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.
Electrical Energy <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Security Perimeter <a href="#">[Archive]</a>	ESP	5/2/2006	1/18/2008 (Becomes inactive 3/31/2016)	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Electronic Security Perimeter <a href="#">[Archive]</a>	ESP	11/26/12	11/22/2013 (Becomes effective 4/1/2016)	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Element <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Element <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.
Emergency or BES Emergency <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Emergency Request for Interchange <a href="#">[Archive]</a>	Emergency RFI	10/29/2008	12/17/2009	Request for Interchange to be initiated for Emergency or Energy Emergency conditions.
Energy Emergency <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Energy Emergency <a href="#">[Archive]</a>		11/13/2014	11/19/2015 effective 4/1/2017	A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Equipment Rating <a href="#">[Archive]</a>		2/7/2006	3/16/2007	The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
External Routable Connectivity <a href="#">[Archive]</a>		11/26/12	11/22/2013 (Becomes effective 4/1/2016)	The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection.
Existing Transmission Commitments <a href="#">[Archive]</a>	ETC	08/22/2008	11/24/2009	Committed uses of a Transmission Service Provider’s Transmission system considered when determining ATC or AFC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Facility <a href="#">[Archive]</a>		2/7/2006	3/16/2007	A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault <a href="#">[Archive]</a>		2/8/2005	3/16/2007	An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk <a href="#">[Archive]</a>		2/7/2006	3/16/2007	The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand <a href="#">[Archive]</a>		2/8/2005	3/16/2007	That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover <a href="#">[Archive]</a>		2/7/2006	3/16/2007	An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.



Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Flowgate <a href="#">[Archive]</a>		08/22/2008	11/24/2009	<p>1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.</p> <p>2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.</p>
Flowgate Methodology <a href="#">[Archive]</a>		08/22/2008	11/24/2009	The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).
Forced Outage <a href="#">[Archive]</a>		2/8/2005	3/16/2007	<p>1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons.</p> <p>2. The condition in which the equipment is unavailable due to unanticipated failure.</p>
Frequency Bias <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Bias Setting <a href="#">[Archive]</a>		2/8/2005	3/16/2007 (Becomes inactive 3/31/2015)	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Bias Setting <a href="#">[Archive]</a>		2/7/2013	1/16/2014 (Becomes effective 4/1/2015)	A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.
Frequency Deviation <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A change in Interconnection frequency.
Frequency Error <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The difference between the actual and scheduled frequency. ( $F_A - F_S$ )
Frequency Regulation <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response <a href="#">[Archive]</a>		2/8/2005	3/16/2007	(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency.  (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Response Measure <a href="#">[Archive]</a>	FRM	2/7/2013	1/16/2014 (Becomes effective 4/1/2015)	The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.
Frequency Response Obligation <a href="#">[Archive]</a>	FRO	2/7/2013	1/16/2014 (Becomes effective 4/1/2015)	The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Response Sharing Group <a href="#">[Archive]</a>	FRSG	2/7/2013	1/16/2014 (Becomes effective 4/1/2015)	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.
Generator Operator <a href="#">[Archive]</a>	GOP	2/8/2005	3/16/2007	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Operator <a href="#">[Archive]</a>	GOP	11/5/2015	1/21/2016 (effective 7/1/2016)	The entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner <a href="#">[Archive]</a>	GO	2/8/2005	3/16/2007	Entity that owns and maintains generating units.
Generator Owner <a href="#">[Archive]</a>	GO	11/5/2015	1/21/2016 (effective 7/1/2016)	Entity that owns and maintains generating Facility(ies).
Generator Shift Factor <a href="#">[Archive]</a>	GSF	2/8/2005	3/16/2007	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor <a href="#">[Archive]</a>	GLDF	2/8/2005	3/16/2007	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Generation Capability Import Requirement <a href="#">[Archive]</a>	GCIR	11/13/2008	11/24/2009	The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.
Host Balancing Authority <a href="#">[Archive]</a>		2/8/2005	3/16/2007	<ol style="list-style-type: none"> <li>1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority’s metered boundaries.</li> <li>2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.</li> </ol>
Hourly Value <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Data measured on a Clock Hour basis.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Implemented Interchange <a href="#">[Archive]</a>		5/2/2006	3/16/2007	The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. (I <sub>A</sub> - I <sub>S</sub> )
Independent Power Producer <a href="#">[Archive]</a>	IPP	2/8/2005	3/16/2007	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc. <a href="#">[Archive]</a>	IEEE	2/7/2006	3/16/2007	

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interactive Remote Access <a href="#">[Archive]</a>		11/26/12	11/22/2013 (Becomes effective 4/1/2016)	User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity’s Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.
Interchange <a href="#">[Archive]</a>		5/2/2006	3/16/2007	Energy transfers that cross Balancing Authority boundaries.
Interchange Authority <a href="#">[Archive]</a>	IA	5/2/2006	3/16/2007	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interchange Authority <a href="#">[Archive]</a>	IA	11/5/2015	1/21/2016 (effective 7/1/2016)	The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interchange Distribution Calculator <a href="#">[Archive]</a>	IDC	2/8/2005	3/16/2007	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.
Interchange Schedule <a href="#">[Archive]</a>		2/8/2005	3/16/2007	An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction <a href="#">[Archive]</a>		2/8/2005	3/16/2007	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnected Operations Service <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	A service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.



Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interconnection <a href="#">[Archive]</a>		2/8/2005	3/16/2007 (Retires 6/30/2016)	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection <a href="#">[Archive]</a>		8/15/2013	4/16/2015 (Effective 7/1/2016)	When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.
Interconnection <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.
Interconnection Reliability Operating Limit <a href="#">[Archive]</a>	IROL	2/8/2005	3/16/2007 Retired 12/27/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.
Interconnection Reliability Operating Limit <a href="#">[Archive]</a>	IROL	11/1/2006	12/27/2007	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages <sup>4</sup> that adversely impact the reliability of the Bulk Electric System.

<sup>4</sup> On September 13, 2012, FERC issued an Order approving NERC’s request to modify the reference to “Cascading Outages” to “Cascading outages” within the definition of IROL due to the fact that the definition of “Cascading Outages” was previously remanded by FERC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interconnection Reliability Operating Limit $T_v$ <a href="#">[Archive]</a>	IROL $T_v$	11/1/2006	12/27/2007	The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's $T_v$ shall be less than or equal to 30 minutes.
Intermediate Balancing Authority <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.
Intermediate Balancing Authority <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
Intermediate System <a href="#">[Archive]</a>		11/26/12	11/22/2013 (Becomes effective 4/1/2016)	A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.
Interpersonal Communication <a href="#">[Archive]</a>		11/7/2012	4/16/2015 (Becomes effective 10/1/2015)	Any medium that allows two or more individuals to interact, consult, or exchange information.
Interruptible Load or Interruptible Demand <a href="#">[Archive]</a>		11/1/2006	3/16/2007	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Joint Control <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Automatic Generation Control of jointly owned units by two or more Balancing Authorities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Limiting Element <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The element that is 1. )Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load <a href="#">[Archive]</a>		2/8/2005	3/16/2007	An end-use device or customer that receives power from the electric system.
Load Shift Factor <a href="#">[Archive]</a>	LSF	2/8/2005	3/16/2007	A factor to be applied to a load’s expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity <a href="#">[Archive]</a>	LSE	2/8/2005	3/16/2007	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Load-Serving Entity <a href="#">[Archive]</a>	LSE	11/5/2015	1/21/2016 (effective 7/1/2016)	Secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Long-Term Transmission Planning Horizon <a href="#">[Archive]</a>		8/4/2011	10/17/2013 (Becomes effective 1/1/2015)	Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.
Low Impact BES Cyber System Electronic Access Point <a href="#">[Archive]</a>	LEAP	2/12/2015	1/21/2016 (effective 7/1/2016)	A Cyber Asset interface that controls Low Impact External Routable Connectivity. The Cyber Asset containing the LEAP may reside at a location external to the asset or assets containing low impact BES Cyber Systems.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Low Impact External Routable Connectivity <a href="#">[Archive]</a>	LERC	2/12/2015	1/21/2016 (effective 7/1/2016)	Direct user-initiated interactive access or a direct device-to-device connection to a low impact BES Cyber System(s) from a Cyber Asset outside the asset containing those low impact BES Cyber System(s) via a bi-directional routable protocol connection. Point-to-point communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions between Transmission station or substation assets containing low impact BES Cyber Systems are excluded from this definition (examples of this communication include, but are not limited to, IEC 61850 GOOSE or vendor proprietary protocols).
Market Flow <a href="#">[Archive]</a>		11/4/2010	4/21/2011	The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.
Minimum Vegetation Clearance Distance <a href="#">[Archive]</a>	MVCD	11/3/2011	3/21/2013 (Becomes effective 7/1/14)	The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Misoperation <a href="#">[Archive]</a>		2/7/2006	3/16/2007	<ul style="list-style-type: none"> <li>Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.</li> <li>Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).</li> <li>Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.</li> </ul>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Misoperation <a href="#">[Archive]</a>		8/14/2014	5/13/2015 (Becomes effective 7/1/2016)	<p>The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:</p> <ol style="list-style-type: none"> <li>1. <b>Failure to Trip – During Fault</b> – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.</li> <li>2. <b>Failure to Trip – Other Than Fault</b> – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.</li> <li>3. <b>Slow Trip – During Fault</b> – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System.</li> </ol> <p><i>(continued below)</i></p>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
<p><i>Continued...</i> Misoperation <a href="#">[Archive]</a></p>		8/14/2014	5/13/2015 (Becomes effective 7/1/2016)	<p><b>4. Slow Trip – Other Than Fault</b> – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System.</p> <p><b>5. Unnecessary Trip – During Fault</b> – An unnecessary Composite Protection System operation for a Fault condition on another Element.</p> <p><b>6. Unnecessary Trip – Other Than Fault</b> – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.</p>
<p>Most Severe Single Contingency <a href="#">[Archive]</a></p>	MSSC	11/5/2015		<p>The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority’s area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).</p>



Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Native Balancing Authority <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Native Load <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The end-use customers that the Load-Serving Entity is obligated to serve.
Near-Term Transmission Planning Horizon <a href="#">[Archive]</a>		1/24/2011	11/17/2011	The transmission planning period that covers Year One through five.
Net Actual Interchange <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Non-Consequential Load Loss <a href="#">[Archive]</a>		8/4/2011	10/17/2013 (Becomes effective 1/1/15)	Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.
Non-Firm Transmission Service <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve <a href="#">[Archive]</a>		2/8/2005	3/16/2007	<ol style="list-style-type: none"> <li>1. That generating reserve not connected to the system but capable of serving demand within a specified time.</li> <li>2. Interruptible load that can be removed from the system in a specified time.</li> </ol>
Normal Clearing <a href="#">[Archive]</a>		11/1/2006	12/27/2007	A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator <a href="#">[Archive]</a>		5/2/2007	10/16/2008	Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Off-site Power Supply (Off-site Power) <a href="#">[Archive]</a>		5/2/2007	10/16/2008	The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Nuclear Plant Licensing Requirements <a href="#">[Archive]</a>	NPLRs	5/2/2007	10/16/2008	Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.
Nuclear Plant Interface Requirements <a href="#">[Archive]</a>	NPIRs	5/2/2007	10/16/2008	The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Off-Peak <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service <a href="#">[Archive]</a>	OASIS	2/8/2005	3/16/2007	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff <a href="#">[Archive]</a>	OATT	2/8/2005	3/16/2007	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Instruction <a href="#">[Archive]</a>		5/6/2014	4/16/2015 (Becomes effective 7/1/2016)	A command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Plan <a href="#">[Archive]</a>		2/7/2006	3/16/2007	A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.
Operating Procedure <a href="#">[Archive]</a>		2/7/2006	3/16/2007	A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process <a href="#">[Archive]</a>		2/7/2006	3/16/2007	A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve <a href="#">[Archive]</a>		2/8/2005	3/16/2007	That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Reserve – Spinning <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: <ul style="list-style-type: none"> <li>• Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or</li> <li>• Load fully removable from the system within the Disturbance Recovery Period following the contingency event.</li> </ul>
Operating Reserve – Supplemental <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: <ul style="list-style-type: none"> <li>• Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or</li> <li>• Load fully removable from the system within the Disturbance Recovery Period following the contingency event.</li> </ul>
Operating Voltage <a href="#">[Archive]</a>		2/7/2006	3/16/2007	The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis <a href="#">[Archive]</a>		10/17/2008	3/17/2011	An analysis of the expected system conditions for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operational Planning Analysis <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Operational Planning Analysis <a href="#">[Archive]</a>		11/13/2014	11/19/2015 (Becomes effective 1/1/2017)	An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Operations Support Personnel <a href="#">[Archive]</a>		2/6/2014	6/19/2014 (effective 7/1/2016)	Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, <sup>1</sup> in direct support of Real-time operations of the Bulk Electric System.
Outage Transfer Distribution Factor <a href="#">[Archive]</a>	OTDF	8/22/2008	11/24/2009	In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).



Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Overlap Regulation Service <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Participation Factors <a href="#">[Archive]</a>		8/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand <a href="#">[Archive]</a>		2/8/2005	3/16/2007	<ol style="list-style-type: none"> <li>1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year).</li> <li>2. The highest instantaneous demand within the Balancing Authority Area.</li> </ol>
Performance-Reset Period <a href="#">[Archive]</a>		2/7/2006	3/16/2007	The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Access Control Systems <a href="#">[Archive]</a>	PACS	11/26/12	11/22/2013 (Becomes effective 4/1/16)	Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.
Physical Security Perimeter <a href="#">[Archive]</a>	PSP	5/2/2006	1/18/2008 (Becomes inactive 3/31/16)	The physical, completely enclosed (“six-wall”) border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Physical Security Perimeter <a href="#">[Archive]</a>	PSP	11/26/12	11/22/2013 (Becomes effective 4/1/16)	The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Planning Assessment <a href="#">[Archive]</a>		8/4/2011	10/17/2013 (Becomes effective 1/1/15)	Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.
Planning Authority <a href="#">[Archive]</a>	PA	2/8/2005	3/16/2007	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Planning Authority <a href="#">[Archive]</a>	PA	11/5/2015	1/21/2016 (effective 7/1/2016)	The responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.
Planning Coordinator <a href="#">[Archive]</a>	PC	8/22/2008	11/24/2009	See Planning Authority.
Point of Delivery <a href="#">[Archive]</a>	POD	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt <a href="#">[Archive]</a>	POR	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Point of Receipt <a href="#">[Archive]</a>	POR	11/5/2015	1/21/2016 (effective 7/1/2016)	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.
Point to Point Transmission Service <a href="#">[Archive]</a>	PTP	2/8/2005	3/16/2007	The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Postback <a href="#">[Archive]</a>		08/22/2008	Not approved; Modification directed 11/24/09	Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.
Power Transfer Distribution Factor <a href="#">[Archive]</a>	PTDF	08/22/2008	11/24/2009	In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer
Pre-Reporting Contingency Event ACE Value <a href="#">[Archive]</a>		11/5/2015		The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.
Pro Forma Tariff <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protected Cyber Assets <a href="#">[Archive]</a>	PCA	11/26/2012	11/22/2013 (Becomes effective 4/1/16)	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP. A Cyber Asset is not a Protected Cyber Asset if, for 30 consecutive calendar days or less, it is connected either to a Cyber Asset within the ESP or to the network within the ESP, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Protected Cyber Assets <a href="#">[Archive]</a>	PCA	2/12/2015	1/21/2016 (effective 7/1/2016)	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.
Protection System <a href="#">[Archive]</a>		2/7/2006	3/17/2007 retired 4/1/2013	Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System <a href="#">[Archive]</a> <a href="#">[Implementation Plan]</a>		11/19/2010	2/3/2012 (Became effective on 4/1/13)	Protection System – <ul style="list-style-type: none"> <li>• Protective relays which respond to electrical quantities,</li> <li>• Communications systems necessary for correct operation of protective functions</li> <li>• Voltage and current sensing devices providing inputs to protective relays,</li> <li>• Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and</li> <li>• Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.</li> </ul>
Protection System Coordination Study <a href="#">[Archive]</a>		11/5/2015		An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System Maintenance Program (PRC-005-2) <a href="#">[Archive]</a>	PSMP	11/7/2012	12/19/2013 (Becomes effective 4/1/2015)	An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities: Verify — Determine that the component is functioning correctly. Monitor — Observe the routine in-service operation of the component. Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. Inspect — Examine for signs of component failure, reduced performance or degradation. Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System Maintenance Program (PRC-005-3) <a href="#">[Archive]</a>	PSMP	11/7/2013	1/22/2015 (Becomes effective 4/1/2016)	An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities: Verify — Determine that the component is functioning correctly. Monitor — Observe the routine in-service operation of the component. Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. Inspect — Examine for signs of component failure, reduced performance or degradation. Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.



Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System Maintenance Program (PRC-005-4) <a href="#">[Archive]</a>	PSMP	11/13/2014	9/17/2015 (Becomes effective 1/1/2016)	An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities: <ul style="list-style-type: none"> <li>• Verify — Determine that the Component is functioning correctly.</li> <li>• Monitor — Observe the routine in-service operation of the Component.</li> <li>• Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.</li> <li>• Inspect — Examine for signs of Component failure, reduced performance or degradation.</li> <li>• Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.</li> </ul>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System Maintenance Program (PRC-005-6) <a href="#">[Archive]</a>	PSMP	11/5/2015		An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities: <ul style="list-style-type: none"> <li>• Verify — Determine that the Component is functioning correctly.</li> <li>• Monitor — Observe the routine in-service operation of the Component.</li> <li>• Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.</li> <li>• Inspect — Examine for signs of Component failure, reduced performance or degradation.</li> <li>• Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.</li> </ul>
Pseudo-Tie <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a “virtual” tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Pseudo-Tie <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).
Purchasing-Selling Entity <a href="#">[Archive]</a>	PSE	2/8/2005	3/16/2007	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Ramp Rate or Ramp <a href="#">[Archive]</a>		2/8/2005	3/16/2007	(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions <a href="#">[Archive]</a>		2/7/2006	3/16/2007	The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate
Rating <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The operational limits of a transmission system element under a set of specified conditions.
Rated System Path Methodology <a href="#">[Archive]</a>		08/22/2008	11/24/2009	The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reactive Power <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Reactive Power <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The portion of electricity that supplies energy to the load.
Real Power <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	The portion of electricity that supplies energy to the Load.
Reallocation <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Real-time <a href="#">[Archive]</a>		2/7/2006	3/16/2007	Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment <a href="#">[Archive]</a>		10/17/2008	3/17/2011	An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data
Real-time Assessment <a href="#">[Archive]</a>		11/13/2014	Revised definition. 11/19/2015 (Becomes effective 1/1/2017)	An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
Receiving Balancing Authority <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The Balancing Authority importing the Interchange.
Regional Reliability Organization <a href="#">[Archive]</a>	RRO	2/8/2005	3/16/2007	<ol style="list-style-type: none"> <li>1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure.</li> <li>2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.</li> </ol>
Regional Reliability Plan <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Regulating Reserve <a href="#">[Archive]</a>		2/8/2005	3/16/2007	An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulation Reserve Sharing Group <a href="#">[Archive]</a>		8/15/2013	4/16/2015 (Becomes effective 7/1/2016)	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.
Regulation Service <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Adjustment Arranged Interchange <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
Reliability Adjustment RFI <a href="#">[Archive]</a>		10/29/2008	12/17/2009	Request to modify an Implemented Interchange Schedule for reliability purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Coordinator <a href="#">[Archive]</a>	RC	2/8/2005	3/16/2007	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator’s vision.
Reliability Coordinator <a href="#">[Archive]</a>	RC	11/5/2015	1/21/2016 (effective 7/1/2016)	The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator’s vision.
Reliability Coordinator Area <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System <a href="#">[Archive]</a>	RCIS	2/8/2005	3/16/2007	The system that Reliability Coordinators use to post messages and share operating information in real time.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Directive <a href="#">[Archive]</a>		8/16/2012	11/19/2015 (Becomes inactive 11/19/2015)	A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact.
Reliability Standard <a href="#">[Archive]</a>		5/9/2013	7/9/2013	A requirement, approved by the United States Federal Energy Regulatory Commission under this Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.



Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Standard <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	A requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for [Reliable Operation] of the [Bulk-Power System]. The term includes requirements for the operation of existing [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for [Reliable Operation] of the [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.
Reliable Operation <a href="#">[Archive]</a>		5/9/2013	7/9/2013	Operating the elements of the bulk-power system [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.
Reliable Operation <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	Operating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.
Remedial Action Scheme <a href="#">[Archive]</a>	RAS	2/8/2005	3/16/2007	See "Special Protection System"

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Remedial Action Scheme <a href="#">[Archive]</a>	RAS	11/13/2014	11/19/2015 effective 4/1/2017	<p>A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:</p> <ul style="list-style-type: none"> <li>• Meet requirements identified in the NERC Reliability Standards;</li> <li>• Maintain Bulk Electric System (BES) stability;</li> <li>• Maintain acceptable BES voltages;</li> <li>• Maintain acceptable BES power flows;</li> <li>• Limit the impact of Cascading or extreme events.</li> </ul> <p>The following do not individually constitute a RAS:</p> <ol style="list-style-type: none"> <li>a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements</li> <li>b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays</li> <li>c. Out-of-step tripping and power swing blocking</li> <li>d. Automatic reclosing schemes</li> <li>e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service</li> </ol>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
<p><b><i>Continued</i></b>  Remedial Action Scheme  <a href="#">[Archive]</a></p>				<ul style="list-style-type: none"> <li>f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated</li> <li>g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device</li> <li>h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched</li> <li>i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open</li> <li>j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)</li> <li>k. Automatic sequences that proceed when manually initiated solely by a System Operator</li> <li>l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations</li> <li>m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)</li> </ul>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
<p><b><i>Continued</i></b> Remedial Action Scheme <a href="#">[Archive]</a></p>				<p>n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing</p>
<p>Removable Media <a href="#">[Archive]</a></p>		2/12/2015	1/21/2016 (effective 7/1/2016)	<p>Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a Protected Cyber Asset. Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.</p>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reportable Balancing Contingency Event <a href="#">[Archive]</a>		11/5/2015		Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity. <ul style="list-style-type: none"> <li>• Eastern Interconnection – 900 MW</li> <li>• Western Interconnection – 500 MW</li> <li>• ERCOT – 800 MW</li> <li>• Quebec – 500 MW</li> </ul>
Reportable Cyber Security Incident <a href="#">[Archive]</a>		11/26/2012	11/22/2013 (Becomes effective 4/1/16)	A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity.
Reportable Disturbance <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority’s or reserve sharing group’s most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reporting ACE <a href="#">[Archive]</a>		8/15/2013	4/16/2015 (Becomes effective 7/1/2016)	<p>The scan rate values of a Balancing Authority’s Area Control Error (ACE) measured in MW, which includes the difference between the Balancing Authority’s Net Actual Interchange and its Net Scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).</p> <p>Reporting ACE is calculated as follows:</p> $\text{Reporting ACE} = (\text{NI}_A - \text{NI}_S) - 10B (\text{F}_A - \text{F}_S) - \text{I}_{\text{ME}}$ <p>Reporting ACE is calculated in the Western Interconnection as follows:</p> $\text{Reporting ACE} = (\text{NI}_A - \text{NI}_S) - 10B (\text{F}_A - \text{F}_S) - \text{I}_{\text{ME}} + \text{I}_{\text{ATEC}}$ <p>Where:</p> <p><b>NI<sub>A</sub> (Actual Net Interchange)</b> is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.</p> <p><b>NI<sub>S</sub> (Scheduled Net Interchange)</b> is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their scheduled Interchange, provided they are implemented in the same manner for Net</p>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reporting ACE (Continued)				<p>Interchange Actual.</p> <p><b>B (Frequency Bias Setting)</b> is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.</p> <p><b>10</b> is the constant factor that converts the frequency bias setting units to MW/Hz.</p> <p><b>F<sub>A</sub> (Actual Frequency)</b> is the measured frequency in Hz.</p> <p><b>F<sub>s</sub> (Scheduled Frequency)</b> is 60.0 Hz, except during a time correction.</p> <p><b>I<sub>ME</sub> (Interchange Meter Error)</b> is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net Interchange energy measurement (in megawatt-hours).</p> <p><b>I<sub>ATEC</sub> (Automatic Time Error Correction)</b> is the addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.</p> $I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)^*H} \text{ when operating in Automatic Time Error Correction control mode.}$ <p><b>I<sub>ATEC</sub></b> shall be zero when operating in any other AGC mode.</p> <ul style="list-style-type: none"> <li>• Y = B / BS.</li> <li>• H = Number of hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.</li> <li>• BS = Frequency Bias for the Interconnection (MW / 0.1 Hz).</li> </ul>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reporting ACE (Continued)				<ul style="list-style-type: none"> <li>• Primary Inadvertent Interchange (<math>PII_{hourly}</math>) is <math>(1-Y) * (II_{actual} - B * \Delta TE/6)</math></li> <li>• <math>II_{actual}</math> is the hourly Inadvertent Interchange for the last hour.</li> <li>• <math>\Delta TE</math> is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:  <math display="block">\Delta TE = TE_{end \text{ hour}} - TE_{begin \text{ hour}} - TD_{adj} - (t) * (TE_{offset})</math> </li> <li>• <math>TD_{adj}</math> is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks.</li> <li>• <math>t</math> is the number of minutes of Manual Time Error Correction that occurred during the hour.</li> <li>• <math>TE_{offset}</math> is 0.000 or +0.020 or -0.020.</li> <li>• <math>PII_{accum}</math> is the Balancing Authority's accumulated <math>PII_{hourly}</math> in MWh. An On-Peak and Off-Peak accumulation accounting is required.</li> </ul> <p>Where:</p> $PII_{accum}^{on/off \text{ peak}} = \text{last period's } PII_{accum}^{on/off \text{ peak}} + PII_{hourly}$ <p>All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an Interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation</p>



Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reporting ACE (Continued)				<p>consistent with the measures included in this standard.</p> <ol style="list-style-type: none"> <li>1. All portions of the Interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.</li> <li>2. The algebraic sum of all area Net Interchange Schedules and all Net Interchange actual values is equal to zero at all times.</li> <li>3. The use of a common Scheduled Frequency FS for all areas at all times.</li> <li>4. The absence of metering or computational errors. (The inclusion and use of the IME term to account for known metering or computational errors.)</li> </ol>
Request for Interchange <a href="#">[Archive]</a>	RFI	5/2/2006	3/16/2007	A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.
Request for Interchange <a href="#">[Archive]</a>	RFI	2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reserve Sharing Group <a href="#">[Archive]</a>	RSG	2/8/2005	3/16/2007	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Reserve Sharing Group <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.
Reserve Sharing Group Reporting ACE <a href="#">[Archive]</a>		8/15/2013	4/16/2015 (Becomes effective 7/1/2016)	At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the Reporting ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the Reserve Sharing Group at the time of measurement.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reserve Sharing Group Reporting ACE <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	At any given time of measurement for the applicable Reserve Sharing Group (RSG), the algebraic sum of the ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the RSG at the time of measurement.
Resource Planner <a href="#">[Archive]</a>	RP	2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Resource Planner <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.
Response Rate <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Right-of-Way <a href="#">[Archive]</a>	ROW	2/7/2006	3/16/2007	A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Right-of-Way <a href="#">[Archive]</a>	ROW	11/3/2011	3/21/2013 (Becomes inactive 6/30/2014)	The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner’s legal rights but may be less based on the aforementioned criteria.
Right-of-Way <a href="#">[Archive]</a>	ROW	5/9/12	3/21/2013 (Becomes effective 7/1/2014)	The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner’s or applicable Generator Owner’s legal rights but may be less based on the aforementioned criteria.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Scenario <a href="#">[Archive]</a>		2/7/2006	3/16/2007	Possible event.
Schedule <a href="#">[Archive]</a>		2/8/2005	3/16/2007	(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency <a href="#">[Archive]</a>		2/8/2005	3/16/2007	60.0 Hertz, except during a time correction.
Scheduling Entity <a href="#">[Archive]</a>		2/8/2005	3/16/2007	An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The Balancing Authority exporting the Interchange.
Sink Balancing Authority <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Sink Balancing Authority <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Source Balancing Authority <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority <a href="#">[Archive]</a>		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.
Special Protection System (Remedial Action Scheme) <a href="#">[Archive]</a>	SPS	2/8/2005	3/16/2007	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spinning Reserve <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Unloaded generation that is synchronized and ready to serve additional demand.
Stability <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Stability Limit <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition <a href="#">[Archive]</a>	SCADA	2/8/2005	3/16/2007	A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.
Surge <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage <a href="#">[Archive]</a>		2/7/2006	3/16/2007	The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A combination of generation, transmission, and distribution components.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
System Operating Limit <a href="#">[Archive]</a>	SOL	2/8/2005	3/16/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: <ul style="list-style-type: none"> <li>• Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)</li> <li>• Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)</li> <li>• Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)</li> <li>• System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)</li> </ul>



Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
System Operating Limit <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: <ul style="list-style-type: none"> <li>• Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)</li> <li>• transient stability ratings (applicable pre- and post-Contingency stability limits)</li> <li>• voltage stability ratings (applicable pre- and post-Contingency voltage stability)</li> <li>• system voltage limits (applicable pre- and post-Contingency voltage limits)</li> </ul>
System Operator <a href="#">[Archive]</a>		2/8/2005	3/16/2007	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
System Operator <a href="#">[Archive]</a>		2/6/2014	6/19/2014 (effective 7/1/2016)	An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System (BES) in Real-time.
Telemetry <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A circuit connecting two Balancing Authority Areas.
Tie Line Bias <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Time Error Correction <a href="#">[Archive]</a>		2/8/2005	3/16/2007	An offset to the Interconnection’s scheduled frequency to return the Interconnection’s Time Error to a predetermined value.
TLR (Transmission Loading Relief) <sup>5</sup> Log <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.
Total Flowgate Capability <a href="#">[Archive]</a>	TFC	08/22/2008	11/24/2009	The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
Total Internal Demand <a href="#">[Archive]</a>		5/6/2014	2/19/2015 (Becomes effective 7/1/2016)	The Demand of a metered system, which includes the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.
Total Transfer Capability <a href="#">[Archive]</a>	TTC	2/8/2005	3/16/2007	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction <a href="#">[Archive]</a>		2/8/2005	3/16/2007	See Interchange Transaction.

<sup>5</sup> NERC added the spelled out term for TLR Log for clarification purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transfer Capability <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The measure of the ability of interconnected electric systems to move or transfer power <i>in a reliable manner</i> from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is <i>not</i> generally equal to the transfer capability from "Area B" to "Area A."
Transfer Distribution Factor <a href="#">[Archive]</a>		2/8/2005	3/16/2007	See Distribution Factor.
Transient Cyber Asset <a href="#">[Archive]</a>		2/12/2015	1/21/2016 (effective 7/1/2016)	A Cyber Asset that (i) is capable of transmitting or transferring executable code, (ii) is not included in a BES Cyber System, (iii) is not a Protected Cyber Asset (PCA), and (iv) is directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless, including near field or Bluetooth communication) for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a PCA. Examples include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Transmission <a href="#">[Archive]</a>		2/8/2005	3/16/2007	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Constraint <a href="#">[Archive]</a>		2/8/2005	3/16/2007	A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer <a href="#">[Archive]</a>		2/8/2005	3/16/2007	<ol style="list-style-type: none"> <li>1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service.</li> <li>2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.</li> </ol>
Transmission Customer <a href="#">[Archive]</a>		11/5/2015	1/21/2016 (effective 7/1/2016)	<ol style="list-style-type: none"> <li>1. Any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can or does receive Transmission Service.</li> <li>2. Any of the following entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.</li> </ol>
Transmission Line <a href="#">[Archive]</a>		2/7/2006	3/16/2007	A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator <a href="#">[Archive]</a>	TOP	2/8/2005	3/16/2007	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
Transmission Operator <a href="#">[Archive]</a>	TOP	11/5/2015	1/21/2016 (effective 7/1/2016)	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Operator Area <a href="#">[Archive]</a>		08/22/2008	11/24/2009	The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner <a href="#">[Archive]</a>	TO	2/8/2005	3/16/2007	The entity that owns and maintains transmission facilities.
Transmission Owner <a href="#">[Archive]</a>	TO	11/5/2015	1/21/2016 (effective 7/1/2016)	The entity that owns and maintains transmission Facilities.
Transmission Planner <a href="#">[Archive]</a>	TP	2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
Transmission Planner <a href="#">[Archive]</a>	TP	11/5/2015	1/21/2016 (effective 7/1/2016)	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.
Transmission Reliability Margin <a href="#">[Archive]</a>	TRM	2/8/2005	3/16/2007	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Reliability Margin Implementation Document <a href="#">[Archive]</a>	TRMID	08/22/2008	11/24/2009	A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator’s calculation of TRM.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Service <a href="#">[Archive]</a>		2/8/2005	3/16/2007	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider <a href="#">[Archive]</a>	TSP	2/8/2005	3/16/2007	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
Transmission Service Provider <a href="#">[Archive]</a>	TSP	11/5/2015	1/21/2016 (effective 7/1/2016)	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.
Undervoltage Load Shedding Program <a href="#">[Archive]</a>	UVLS Program	11/13/2014	11/19/2015 effective 4/1/2017	An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.
Vegetation <a href="#">[Archive]</a>		2/7/2006	3/16/2007	All plant material, growing or not, living or dead.
Vegetation Inspection <a href="#">[Archive]</a>		2/7/2006	3/16/2007	The systematic examination of a transmission corridor to document vegetation conditions.
Vegetation Inspection <a href="#">[Archive]</a>		11/3/2011	3/21/2013 (Becomes inactive 6/30/2014)	The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Vegetation Inspection <a href="#">[Archive]</a>		5/9/12	3/21/2013 (Becomes effective 7/1/2014)	The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner’s or applicable Generator Owner’s control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Wide Area <a href="#">[Archive]</a>		2/8/2005	3/16/2007	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.
Year One <a href="#">[Archive]</a>		1/24/2011	11/17/2011	The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.



## ERCOT Regional Definitions

The following terms were developed as regional definitions for the ERCOT region:

ERCOT Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Measurable Event <a href="#">[Archive]</a>	FME	8/15/2013	1/16/2014 (Becomes effective 4/1/14)	An event that results in a Frequency Deviation, identified at the BA's sole discretion, and meeting one of the following conditions:  i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year).  Or  ii) a cumulative change in generating unit/generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year).
Governor <a href="#">[Archive]</a>		8/15/2013	1/16/2014 (Becomes effective	The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

ERCOT Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
			4/1/14)	
Primary Frequency Response <a href="#">[Archive]</a>	PFR	8/15/2013	1/16/2014 (Becomes effective 4/1/14)	The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

## NPCC Regional Definitions

The following definitions were developed for use in NPCC Regional Standards.

NPCC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Current Zero Time <a href="#">[Archive]</a>		11/04/2010	10/20/2011	The time of the final current zero on the last phase to interrupt.
Generating Plant <a href="#">[Archive]</a>		11/04/2010	10/20/2011	One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

### ReliabilityFirst Regional Definitions

The following definitions were developed for use in ReliabilityFirst Regional Standards.

RFC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Resource Adequacy <a href="#">[Archive]</a>		08/05/2009	03/17/2011	The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)
Net Internal Demand <a href="#">[Archive]</a>		08/05/2009	03/17/2011	Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand
Peak Period <a href="#">[Archive]</a>		08/05/2009	03/17/2011	A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur
Wind Generating Station <a href="#">[Archive]</a>		11/03/2011		A collection of wind turbines electrically connected together and injecting energy into the grid at one point, sometimes known as a "Wind Farm."
Year One <a href="#">[Archive]</a>		08/05/2009	03/17/2011	The planning year that begins with the upcoming annual Peak Period

## WECC Regional Definitions

The following definitions were developed for use in WECC Regional Standards.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Area Control Error <sup>†</sup> <a href="#">[Archive]</a>	ACE	3/12/2007	6/8/2007 (Becomes inactive 3/31/14)	Means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.
Automatic Generation Control <sup>‡</sup> <a href="#">[Archive]</a>	AGC	3/12/2007	6/8/2007	Means equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.
Automatic Time Error Correction <a href="#">[Archive]</a>		3/26/2008	5/21/2009 (Becomes inactive 3/31/14)	A frequency control automatic action that a Balancing Authority uses to offset its frequency contribution to support the Interconnection's scheduled frequency.
Automatic Time Error Correction <a href="#">[Archive]</a>		12/19/2012	10/16/2013 (Becomes effective 4/1/2014)	The addition of a component to the ACE equation that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error.
Average Generation <sup>‡</sup> <a href="#">[Archive]</a>		3/12/2007	6/8/2007	Means the total MWh generated within the Balancing Authority Operator's Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).
Business Day <sup>‡</sup> <a href="#">[Archive]</a>		3/12/2007	6/8/2007	Means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Commercial Operation <a href="#">[Archive]</a>		10/29/2008	4/21/2011	Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
Contributing Schedule <a href="#">[Archive]</a>		2/10/2009	3/17/2011	A Schedule not on the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.
Dependability-Based Misoperation <a href="#">[Archive]</a>		10/29/2008	4/21/2011	Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.
Disturbance <sup>±</sup> <a href="#">[Archive]</a>		3/12/2007	6/8/2007	Means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Extraordinary Contingency <sup>±</sup> <a href="#">[Archive]</a>		3/12/2007	6/8/2007	Shall have the meaning set out in Excuse of Performance, section B.4.c. language in section B.4.c: <i>means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the "Most Severe Single Contingency" as defined in the WECC Reliability Criteria or any lesser contingency).</i>
Frequency Bias <sup>±</sup> <a href="#">[Archive]</a>		3/12/2007	6/8/2007	Means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.
Functionally Equivalent Protection System <a href="#">[Archive]</a>	FEPS	10/29/2008	4/21/2011	A Protection System that provides performance as follows: <ul style="list-style-type: none"> <li>• Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards.</li> <li>• Each Protection System may have different components and operating characteristics.</li> </ul>
Functionally Equivalent RAS <a href="#">[Archive]</a>	FERAS	10/29/2008	4/21/2011	A Remedial Action Scheme ("RAS") that provides the same performance as follows: <ul style="list-style-type: none"> <li>• Each RAS can detect the same conditions and provide</li> </ul>

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
				mitigation to comply with all Reliability Standards. <ul style="list-style-type: none"> <li>• Each RAS may have different components and operating characteristics.</li> </ul>
Generating Unit Capability <sup>±</sup> <a href="#">[Archive]</a>		3/12/2007	6/8/2007	Means the MVA nameplate rating of a generator.
Non-spinning Reserve <sup>±</sup> <a href="#">[Archive]</a>		3/12/2007	6/8/2007	Means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.
Normal Path Rating <sup>±</sup> <a href="#">[Archive]</a>		3/12/2007	6/8/2007	Is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.
Operating Reserve <sup>±</sup> <a href="#">[Archive]</a>		3/12/2007	6/8/2007	Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.
Operating Transfer Capability Limit <sup>±</sup> <a href="#">[Archive]</a>	OTC	3/12/2007	6/8/2007	Means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.



WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Primary Inadvertent Interchange <a href="#">[Archive]</a>		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of the area (n).
Qualified Controllable Device <a href="#">[Archive]</a>		2/10/2009	3/17/2011	A controllable device installed in the Interconnection for controlling energy flow and the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.
Qualified Transfer Path <a href="#">[Archive]</a>		2/10/2009	3/17/2011	A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.
Qualified Transfer Path Curtailment Event <a href="#">[Archive]</a>		2/10/2009	3/17/2011	Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (See Attachment 1 IRO-006-WECC-1) during which the curtailment tool is functional.
Relief Requirement <a href="#">[Archive]</a>		2/10/2009	3/17/2011 (Becomes inactive 6/30/2014)	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.
Relief Requirement <a href="#">[Archive]</a>		2/7/2013	6/13/2014 (Becomes effective 7/1/2014)	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages determined in the WECC unscheduled flow mitigation guideline.
Secondary Inadvertent		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interchange <a href="#">[Archive]</a>				the regulating deficiencies of area (i).
Security-Based Misoperation <a href="#">[Archive]</a>		10/29/2008	4/21/2011	A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure of a device’s certainty not to operate falsely.
Spinning Reserve <sup>†</sup> <a href="#">[Archive]</a>		3/12/2007	6/8/2007	Means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).
Transfer Distribution Factor <a href="#">[Archive]</a>	TDF	2/10/2009	3/17/2011	The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]
WECC Table 2 <sup>†</sup> <a href="#">[Archive]</a>		3/12/2007	6/8/2007	Means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.

Endnotes

<sup>†</sup> FERC approved the WECC Tier One Reliability Standards in the Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007). In that Order, FERC directed WECC to address the inconsistencies between the regional definitions and the NERC Glossary in developing permanent replacement standards. The replacement standards designed to address the shortcomings were filed with FERC in 2009.

**Exhibit C**  
**List of Currently Effective NERC Reliability Standards**

<b>Resource and Demand Balancing (BAL)</b>	
BAL-001-1	<a href="#">Real Power Balancing Control Performance</a>
BAL-001-TRE-1	<a href="#">Primary Frequency Response in the ERCOT Region</a>
BAL-002-1	<a href="#">Disturbance Control Performance</a>
BAL-002-WECC-2	<a href="#">Contingency Reserve</a>
BAL-003-1.1	<a href="#">Frequency Response and Frequency Bias Setting</a>
BAL-004-0	<a href="#">Time Error Correction</a>
BAL-004-WECC-02	<a href="#">Automatic Time Error Correction (ATEC)</a>
BAL-005-0.2b	<a href="#">Automatic Generation Control</a>
BAL-006-2	<a href="#">Inadvertent Interchange</a>
BAL-502-RFC-02	<a href="#">Planning Resource Adequacy Analysis, Assessment and Documentation</a>
<b>Communications (COM )</b>	
COM-001-1.1	<a href="#">Telecommunications</a>
COM-001-2.1	<a href="#">Communications</a>
COM-002-2	<a href="#">Communications and Coordination</a>
<b>Critical Infrastructure Protection (CIP)</b>	
CIP-002-3	<a href="#">Cyber Security — Critical Cyber Asset Identification</a>
CIP-003-3	<a href="#">Cyber Security — Security Management Controls</a>
CIP-004-3a	<a href="#">Cyber Security — Personnel &amp; Training</a>
CIP-005-3a	<a href="#">Cyber Security — Electronic Security Perimeter(s)</a>
CIP-006-3c	<a href="#">Cyber Security — Physical Security of Critical Cyber Assets</a>
CIP-007-3a	<a href="#">Cyber Security — Systems Security Management</a>
CIP-008-3	<a href="#">Cyber Security — Incident Reporting and Response Planning</a>
CIP-009-3	<a href="#">Cyber Security — Recovery Plans for Critical Cyber Assets</a>

CIP-014-2	<a href="#">Physical Security</a>
<b>Emergency Preparedness and Operations (EOP)</b>	
EOP-001-2.1b	<a href="#">Emergency Operations Planning</a>
EOP-002-3.1	<a href="#">Capacity and Energy Emergencies</a>
EOP-003-2	<a href="#">Load Shedding Plans</a>
EOP-004-2	<a href="#">Event Reporting</a>
EOP-005-2	<a href="#">System Restoration from Blackstart Resources</a>
EOP-006-2	<a href="#">System Restoration Coordination</a>
EOP-008-1	<a href="#">Loss of Control Center Functionality</a>
EOP-010-1	<a href="#">Geomagnetic Disturbance Operations</a>
<b>Facilities Design, Connections, and Maintenance (FAC )</b>	
FAC-001-2	<a href="#">Facility Interconnection Requirements</a>
FAC-002-2	<a href="#">Facility Interconnection Studies</a>
FAC-003-3	<a href="#">Transmission Vegetation Management</a>
FAC-008-3	<a href="#">Facility Ratings</a>
FAC-010-2.1	<a href="#">System Operating Limits Methodology for the Planning Horizon</a>
FAC-011-2	<a href="#">System Operating Limits Methodology for the Operations Horizon</a>
FAC-013-2	<a href="#">Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon</a>
FAC-014-2	<a href="#">Establish and Communicate System Operating Limits</a>
FAC-501-WECC-1	<a href="#">Transmission Maintenance</a>
<b>Interchange Scheduling and Coordination (INT)</b>	
INT-004-3.1	<a href="#">Dynamic Transfers</a>
INT-006-4	<a href="#">Evaluation of Interchange Transactions</a>
INT-009-2.1	<a href="#">Implementation of Interchange</a>
INT-010-2.1	<a href="#">Interchange Initiation and Modification for Reliability</a>
INT-011-1.1	<a href="#">Intra-Balancing Authority Transaction Identification</a>

<b>Interconnection Reliability Operations and Coordination (IRO)</b>	
IRO-001-1.1	<a href="#">Reliability Coordination — Responsibilities and Authorities</a>
IRO-002-2	<a href="#">Reliability Coordination — Facilities</a>
IRO-003-2	<a href="#">Reliability Coordination — Wide-Area View</a>
IRO-004-2	<a href="#">Reliability Coordination — Operations Planning</a>
IRO-005-3.1a	<a href="#">Reliability Coordination — Current Day Operations</a>
IRO-006-5	<a href="#">Reliability Coordination — Transmission Loading Relief (TLR)</a>
IRO-006-EAST-1	<a href="#">Transmission Loading Relief Procedure for the Eastern Interconnection</a>
IRO-006-TRE-1	<a href="#">IROL and SOL Mitigation in the ERCOT Region</a>
IRO-006-WECC-2	<a href="#">Qualified Transfer Path Unscheduled Flow (USF) Relief</a>
IRO-008-1	<a href="#">Reliability Coordinator Operational Analyses and Real-time Assessments</a>
IRO-009-2	<a href="#">Reliability Coordinator Actions to Operate Within IROLs</a>
IRO-010-1a	<a href="#">Reliability Coordinator Data Specification and Collection</a>
IRO-014-1	<a href="#">Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators</a>
IRO-015-1	<a href="#">Notifications and Information Exchange Between Reliability Coordinators</a>
IRO-016-1	<a href="#">Coordination of Real-time Activities Between Reliability Coordinators</a>
<b>Modeling, Data, and Analysis (MOD )</b>	
MOD-001-1a	<a href="#">Available Transmission System Capability</a>
MOD-004-1	<a href="#">Capacity Benefit Margin</a>
MOD-008-1	<a href="#">Transmission Reliability Margin Calculation Methodology</a>
MOD-010-0	<a href="#">Steady-State Data for Modeling and Simulation of the Interconnected Transmission System</a>

MOD-012-0	<a href="#">Dynamics Data for Modeling and Simulation of the Interconnected Transmission System</a>
MOD-016-1.1	<a href="#">Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management</a>
MOD-017-0.1	<a href="#">Aggregated Actual and Forecast Demands and Net Energy for Load</a>
MOD-018-0	<a href="#">Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load</a>
MOD-019-0.1	<a href="#">Reporting of Interruptible Demands and Direct Control Load Management</a>
MOD-020-0	<a href="#">Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators</a>
MOD-021-1	<a href="#">Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts</a>
MOD-026-1	<a href="#">Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions</a>
MOD-027-1	<a href="#">Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions</a>
MOD-028-2	<a href="#">Area Interchange Methodology</a>
MOD-029-1a	<a href="#">Rated System Path Methodology</a>
MOD-030-2	<a href="#">Flowgate Methodology</a>
MOD-032-1	<a href="#">Data for Power System Modeling and Analysis</a>
<b>Nuclear (NUC)</b>	
NUC-001-3	<a href="#">Nuclear Plant Interface Coordination</a>
<b>Personnel Performance, Training, and Qualifications (PER )</b>	
PER-001-0.2	<a href="#">Operating Personnel Responsibility and Authority</a>
PER-003-1	<a href="#">Operating Personnel Credentials</a>
PER-004-2	<a href="#">Reliability Coordination — Staffing</a>
PER-005-1	<a href="#">System Personnel Training</a>

<b>Protection and Control (PRC)</b>	
PRC-001-1.1(ii)	<a href="#">System Protection Coordination</a>
PRC-002-NPCC-01	<a href="#">Disturbance Monitoring</a>
PRC-004-2.1(i)a	<a href="#">Analysis and Mitigation of Transmission and Generation Protection System Misoperations</a>
PRC-004-WECC-1	<a href="#">Protection System and Remedial Action Scheme Misoperation</a>
PRC-005-1.1b	<a href="#">Transmission and Generation Protection System Maintenance and Testing</a>
PRC-005-2(i)	<a href="#">Protection System Maintenance</a>
PRC-005-6	<a href="#">Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance</a>
PRC-006-2	<a href="#">Automatic Underfrequency Load Shedding</a>
PRC-006-NPCC-1	<a href="#">Automatic Underfrequency Load Shedding</a>
PRC-006-SERC-01	<a href="#">Automatic Underfrequency Load Shedding Requirements</a>
PRC-008-0	<a href="#">Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program</a>
PRC-010-0	<a href="#">Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program</a>
PRC-011-0	<a href="#">Undervoltage Load Shedding System Maintenance and Testing</a>
PRC-015-0	<a href="#">Special Protection System Data and Documentation</a>
PRC-016-0.1	<a href="#">Special Protection System Misoperations</a>
PRC-017-0	<a href="#">Special Protection System Maintenance and Testing</a>
PRC-018-1	<a href="#">Disturbance Monitoring Equipment Installation and Data Reporting</a>
PRC-021-1	<a href="#">Under-Voltage Load Shedding Program Data</a>
PRC-022-1	<a href="#">Under-Voltage Load Shedding Program Performance</a>
PRC-023-3	<a href="#">Transmission Relay Loadability</a>
PRC-025-1	<a href="#">Generator Relay Loadability</a>



<b>Transmission Operations (TOP)</b>	
TOP-001-1a	<a href="#">Reliability Responsibilities and Authorities</a>
TOP-002-2.1b	<a href="#">Normal Operations Planning</a>
TOP-003-1	<a href="#">Planned Outage Coordination</a>
TOP-004-2	<a href="#">Transmission Operations</a>
TOP-005-2a	<a href="#">Operational Reliability Information</a>
TOP-006-2	<a href="#">Monitoring System Conditions</a>
TOP-007-0	<a href="#">Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations</a>
TOP-007-WECC-1a	<a href="#">System Operating Limits</a>
TOP-008-1	<a href="#">Response to Transmission Limit Violations</a>
<b>Transmission Planning (TPL)</b>	
TPL-001-4	<a href="#">Transmission System Planning Performance Requirements</a>
<b>Voltage and Reactive (VAR)</b>	
VAR-001-4.1	<a href="#">Voltage and Reactive Control</a>
VAR-002-4	<a href="#">Generator Operation for Maintaining Network Voltage Schedules</a>
VAR-002-WECC-2	<a href="#">Automatic Voltage Regulators (AVR)</a>
VAR-501-WECC-2	<a href="#">Power System Stabilizer (PSS)</a>