Exhibit A

Proposed Reliability Standards

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1(i)a
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
   - **4.1.** Transmission Owner.
   - **4.2.** Distribution Provider that owns a transmission Protection System.
   - **4.3.** Generator Owner.
5. **Effective Date:** See the Implementation Plan for this Standard.

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. 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. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

F. Associated Documents

None.

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. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
2.1(i)a	November 13, 2014	Adopted by the Board of Trustees	Applicability revised in Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources

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 this version of PRC-004-2.1(i)a are revisions to Requirements R2 and R3 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, Requirement R2 and Requirement R3 reflect the threshold consistent with the revised BES definition. See paragraph 20 of FERC Order Approving Revised Definition in Docket No. RD14-2-000. The intent of Requirement R2 and Requirement R3 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.

Appendix 1[1]

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop

[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

Question:

Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?

Response:

The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES.

A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.
3. 45-day formal comment period with initial ballot conducted July 10, 2014 through August 26, 2014. .
4. Posted for additional comment and ballot September 5, 2014 through October 22, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. A subsequent version of PRC-004, i.e., PRC-004-3, also is under active standard development. Depending on the timing of regulatory approval, this interim version, which had been labeled PRC-004-2.1a(X) and is now labeled PRC-004-2.1(i)a for final balloting purposes, may be filed for regulatory approval. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT adoption	November 2015

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1a(X)
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
   - **4.1.** Transmission Owner.
   - **4.2.** Distribution Provider that owns a transmission Protection System.
   - **4.3.** Generator Owner.
5. ~~**(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.~~ **Effective Date:** See the Implementation Plan for this Standard.

Rationale for Introduction: The only revisions made to this version of PRC-004-2.1(i)a are revisions to Requirements R2 and R3 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, Requirement R2 and Requirement R3 reflect the threshold consistent with the revised BES definition. See paragraph 20 of FERC Order Approving Revised Definition in Docket No. RD14-2-000. The intent of Requirement R2 and Requirement R3 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

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~Regional Entity.~~

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. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	

1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
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2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
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2.1(i)a	November 13, 2014	Adopted by the Board of Trustees	Applicability revised in Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources

Appendix 1[1]

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-4

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.[1]

   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.

5. **Background**:

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- 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.
- 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).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

6. Effective Dates:

See the Implementation Plan for this Standard.

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
R1	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
R3	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
R4	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**
R5	Operations Planning, Long-Term Planning	Medium	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. OR (See next page)	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. OR (See next page)	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. OR (See next page)	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. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

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.[2]

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. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by NERC Board of Trustees	

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

1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by NERC Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
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 revised in Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] 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*[4]; 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*[5] 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[6]." 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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[3] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[4] "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

[5] "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

[6] "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.

> **Example7c:** 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*[7] 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.

> **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.

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

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.[8]

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.

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*

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[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

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).

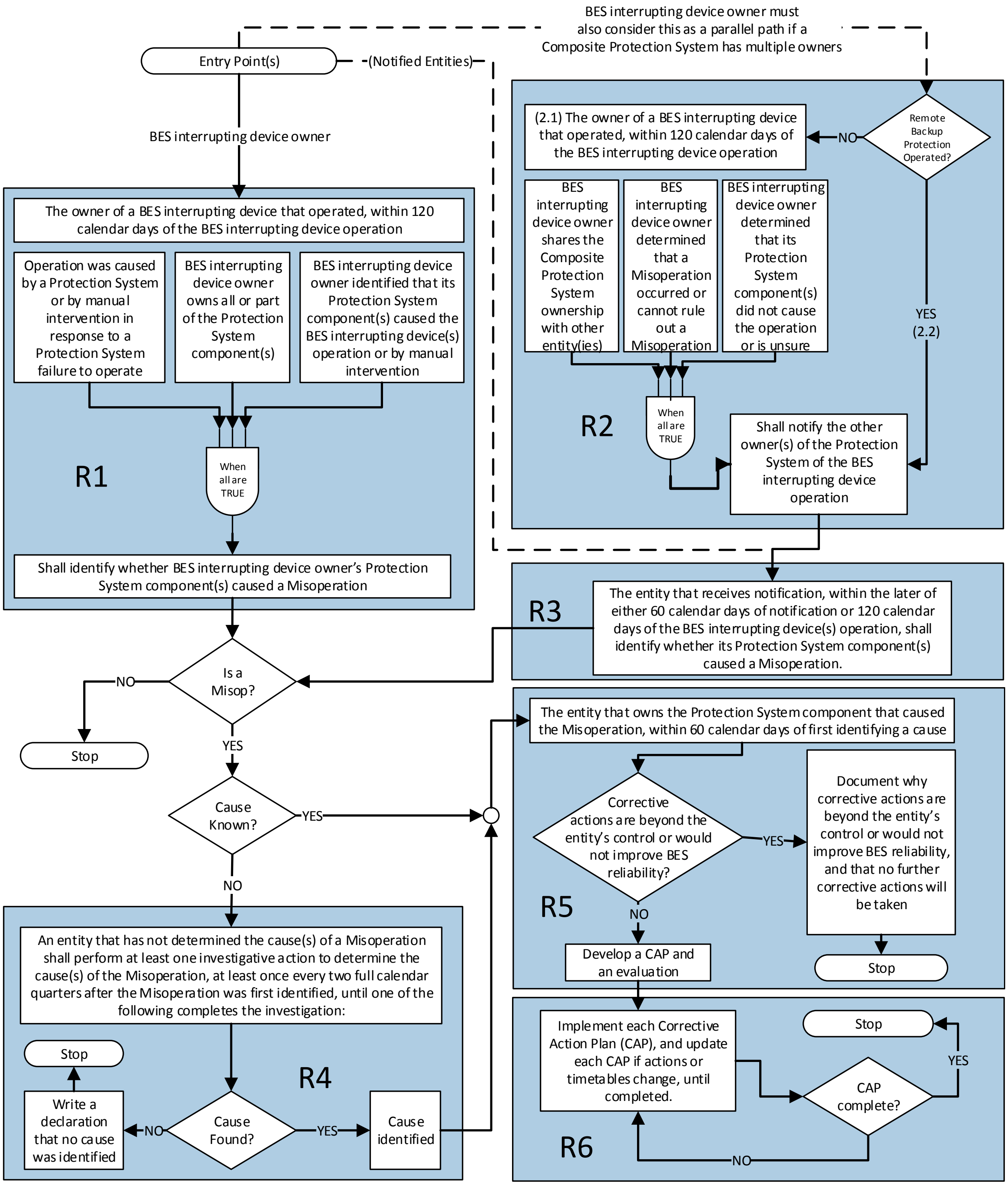
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance 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 this version of PRC-004 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard to 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:
Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded in this standard because they are planned to be handled in the second phase of Project 2010-05.1 .

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.

Rationale for R1:

This Requirement ensures that entities review those Protection System operations meeting the circumstances in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner is assigned the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection

System operations, and provides the opportunity to identify any Misoperations which were initially missed.

Rationale for R2:

Part 2.1 ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System. The phrase “owner(s) that share Misoperation identification responsibility” allows entities to notify the specific other owners that will actually review the operation to determine if a Misoperation occurred. Part 2.2 ensures that the Protection System owner(s) for which backup protection was provided receives notification, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that Part 2.1, 2.2, or both are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.

Rationale for R3:

When an entity receives notification of a Protection System operation by the BES interrupting device owner, the other Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.
3. 45-day formal comment period with initial ballot conducted July 10, 2014 through August 26, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. The currently effective version of PRC-004, i.e., PRC-004-2.1a, also is under active standard development. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT adoption	November 2014

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.	01/20/06

		Changed "Timeframe" to "Time Frame" in item D, 1.2.	
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by NERC Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by NERC Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
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 revised in Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources.

When this standard has received ballot approval, the rationale boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**
2. **Number:** PRC-004-~~3~~4
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.[1]

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.

Rationale for Introduction: The only revisions made to this version of PRC-004 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

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

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.

5. Background:

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- 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.
- 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).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

6. Effective Dates:

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

See the Implementation Plan for this Standard.

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, ~~Disturbance Monitoring Equipment (~~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, ~~Disturbance Monitoring Equipment (DME)~~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
R1	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
R3	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
R4	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**
R5	Operations Planning, Long-Term Planning	Medium	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. OR (See next page)	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. OR (See next page)	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. OR (See next page)	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. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

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.[2]

~~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.~~ ~~Changed "Timeframe" to "Time Frame" in item D, 1.2.~~	~~01/20/06~~
~~2~~		~~Modified to address Order No. 693 Directives contained in paragraph 1469.~~	~~Revised~~

[2] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

~~2~~	~~August 5, 2010~~	~~Adopted by NERC Board of Trustees~~	
~~1a~~	~~February 17, 2011~~	~~Added Appendix 1 – Interpretation regarding applicability of standard to protection of radially connected transformers~~	~~Project 2009-17 interpretation~~
~~1a~~	~~February 17, 2011~~	~~Adopted by the Board of Trustees~~	
~~1a~~	~~September 26, 2011~~	~~FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)~~	
~~2a~~	~~September 26, 2011~~	~~Appended FERC-approved interpretation of R1 and R3 to version 2~~	
~~2.1a~~		~~Errata change: Edited R2 to add "…and generator interconnection Facility…"~~	~~Revision under Project 2010-07~~
~~2.1a~~	~~February 9, 2012~~	~~Errata change adopted by the Board of Trustees~~	
~~2.1a~~	~~September 19, 2013~~	~~FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).~~	
~~3~~	~~August 14, 2014~~	~~Adopted by Board of Trustees~~	~~Revision under Project 2010-05.1~~

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] 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*[4]; 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*[5] 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[6]." 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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[3] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[4] "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

[5] "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

[6] "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.

Example7c: 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 ~~Disturbance Monitoring Equipment (~~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*[7] 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.

> **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

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

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.[8]

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.

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: 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.

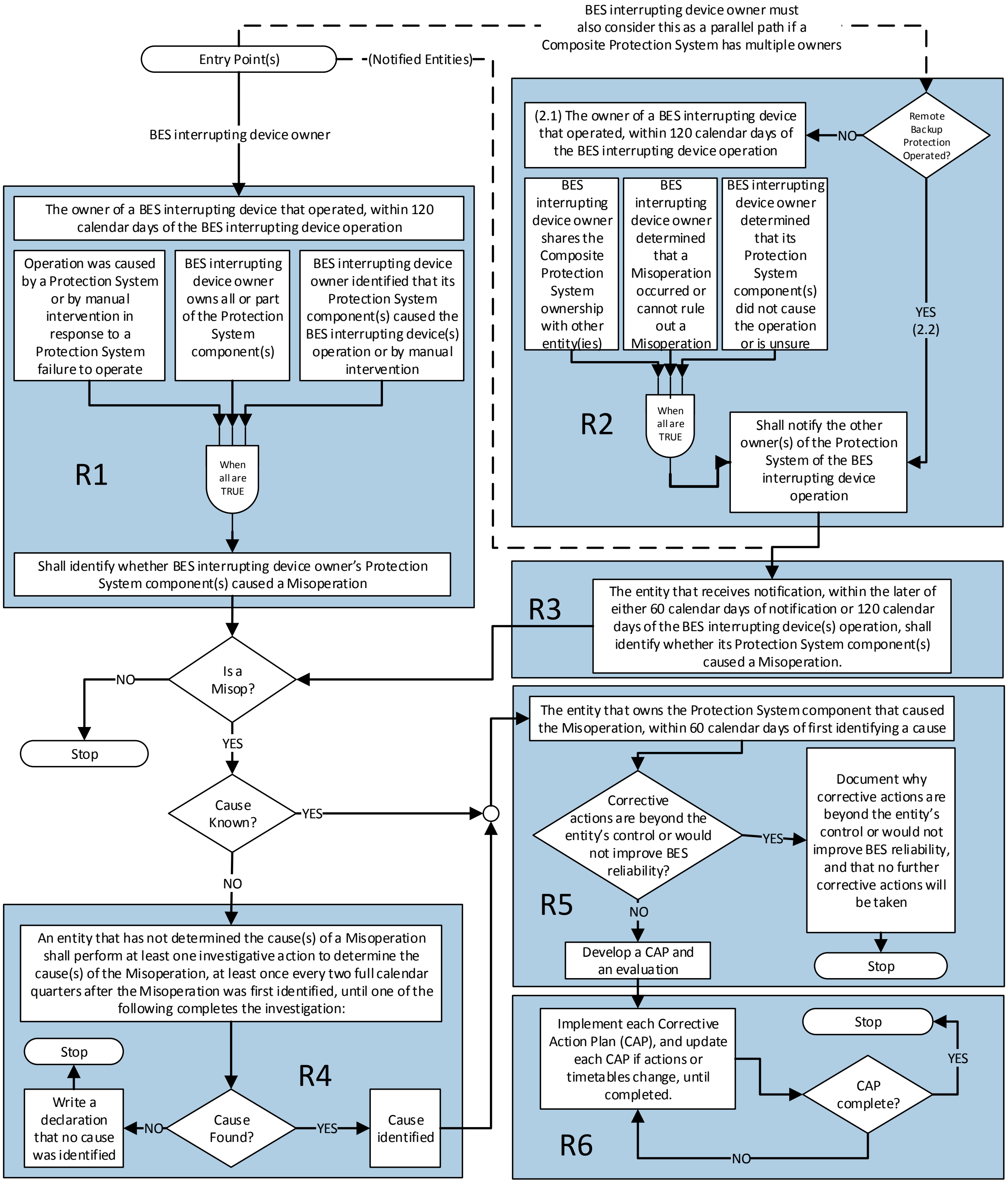
CAP completed on 03/09/2015.

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 were moved to this section.

Rationale for Applicability:

Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded in this standard because they are planned to be handled in the second phase of this project.

Rationale for R1:

This Requirement ensures that entities review those Protection System operations meeting the circumstances in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner is assigned the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed.

Rationale for R2:

Part 2.1 ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System. The phrase "owner(s) that share Misoperation identification responsibility" allows entities to notify the specific other owners that will actually review the operation to determine if a Misoperation occurred. Part 2.2 ensures that the Protection System owner(s) for which backup protection was provided receives notification, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that Part 2.1, 2.2, or both are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.

Rationale for R3:

When an entity receives notification of a Protection System operation by the BES interrupting device owner, the other Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

Rationale for R4:

If a Misoperation cause is not identified within the time period established by Requirements R1 or R3 (i.e., 120 calendar days), the Protection System component owner must demonstrate investigative actions toward identifying the cause(s). Performing at least one action every two full calendar quarters from first identifying the Misoperation encourages periodic focus on finding the cause of the Misoperation.

Rationale for R5:

A formal CAP is a proven tool for resolving and reducing the possibility of reoccurrence of operational problems. A time period of 60 calendar days is based on industry experience and operational coordination time needed for considering such things as alternative solutions, coordination of resources, or development of a schedule. When the cause of a Misoperation is identified, a CAP will generally be developed. An evaluation of the CAP's applicability to the entity's other Protection Systems including other locations helps identify similar problems, the potential for Misoperation occurrences in other Protection Systems, common mode failure, design problems, etc.
In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, a statement documenting the reasons for taking no corrective actions is essential for future reference and for justifying the absence of a CAP.

Rationale for R6:

Each CAP must accomplish all identified objectives to be complete. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion.

A. Introduction

1. **Title:** **Protection System Maintenance**

2. **Number:** PRC-005-2(i)

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems 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 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 Special Protection System (SPS) for BES reliability.

4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:

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 for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems 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 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 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 100 kV or above.

5. **Effective Date:** See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[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 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.

> ***Component Type** - Any one of the five specific elements of the Protection System definition.*

1.2. Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.

> **Component** – *A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.*

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System 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, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

> ***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.*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System 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 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, and Table 3. (Part 1.2)

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.

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 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.

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 Protection System Maintenance Program for the Protection System 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.

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.

D. 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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, 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.

Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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 responsible 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)	The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to:

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				• Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

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	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. Changed "Timeframe" to "Time Frame" in item D, 1.2
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
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) *See N. Amer. Elec. Reliability Corp.*, 138 FERC ¶ 61,095 (February 3, 2012)
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

Version	Date	Action	Change Tracking
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
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	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(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(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(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

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[1]	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[1] 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**[1]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack
	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>
<tr><th colspan="3">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 SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="3">Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
• Station dc supply voltage
Inspect:
• Electrolyte level
• For unintentional grounds</td></tr>
<tr><td>18 Calendar Months</td><td>Verify:
• Float voltage of battery charger
• Battery continuity
• Battery terminal connection resistance
• Battery intercell or unit-to-unit connection resistance
Inspect:
• Cell condition of all individual battery cells.
• Physical condition of battery rack</td></tr>
<tr><td>6 Calendar Years</td><td>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.</td></tr>
</table>

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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) **Note:** Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS.	12 calendar years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5 and Table 3, 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 and Table 3 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	Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

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).

Segment – *Protection Systems or 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.*

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 of the Protection System Component population, 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 and Table 3 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.

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 and Table 3 which requires corrective action, or a 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 configuration errors, or Protection System application errors are not included in Countable Events.*

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Protection System 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.
5. If the Components in a Protection System 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.

Application Guidelines

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 4.2.5

In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

Rationale for 4.2.6:

Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

A. Introduction

1. **Title:** **Protection System Maintenance**

2. **Number:** PRC-005-2(i)

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems 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 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 Special Protection System (SPS) for BES reliability.

4.2.5 Protection Systems for the following BES generator Facilities ~~that are part~~for generators not identified through Inclusion I4 of the BES~~, including~~ definition:

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 for generator step-up transformers for generators that are part of the BES.

~~**4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).~~

~~**4.2.5.4**~~**4.2.5.3** Protection Systems 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 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 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 100 kV or above.

5. Effective Date: See Implementation Plan.

~~5.~~

> ***Component Type*** *- Any one of the five specific elements of the Protection System definition.*

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

> **Component** – *A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.*

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 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 Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.

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]*

> ***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.*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System 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, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System 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 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, and Table 3. (Part 1.2)

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.

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 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.

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 Protection System Maintenance Program for the Protection System 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.

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.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~Regional Entity~~

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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, 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.

~~2.~~ Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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 responsible 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)	The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). ~~OR~~ OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
		with their performance-based PSMP.		with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

Version History

Version	Date	Action	Change Tracking
0	~~April 1~~February 8, 2005	~~Effective Date~~Adopted by NERC Board of Trustees	New
1	~~December 1, 2005~~February 7, 2006	~~1.~~ Adopted by NERC Board of Trustees~~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.~~	~~4.~~ 1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." ~~5.~~ 2. Added "periods" to items where appropriate. Changed "Timeframe" to "Time Frame" in item D, 1.2~~01/20/05~~
1a	February 17, 2011	~~Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers~~Adopted by NERC Board of Trustees	~~Project 2009-17 interpretation~~Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17
~~1a~~1b	~~February 17, 2011~~November 5, 2009	Adopted by NERC Board of Trustees	Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10
~~1a~~1b	February 3, 2012~~September 26, 2011~~	FERC ~~Order issued~~order approving ~~interpretation~~revised definition of ~~R1 and R2 (FERC's Order is effective as of September 26, 2011)~~"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) *See N. Amer. Elec. Reliability Corp.*, 138 FERC ¶ 61,095 (February 3, 2012)

Version	Date	Action	Change Tracking
1.~~1a~~1b	~~February 1~~May 9, 2012	~~Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility~~ Adopted by NERC Board of Trustees	~~Revision under Project 2010-07~~Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner's responsibility
~~1b~~	~~February 3, 2012~~	~~FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.~~	~~Project 2009-10 Interpretation~~
~~1.1b~~	~~April 23, 2012~~	~~Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.~~	~~Revision under Project 2010-07~~

Version	Date	Action	Change Tracking
~~1.1b~~	~~May 9, 2012~~	~~PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).~~	
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
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.~~	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	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(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
~~2~~3	~~**December 19, 2013**~~February 12, 2014	~~**FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 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)
~~2~~3	~~**May**~~March 7, 2014	Adopted by ~~**the**~~ NERC Board of Trustees ~~**to modify VSLs for Requirement R1.**~~	Modified R1 VSL in response to FERC directive (no change to standard version number)
~~2~~3(i)	~~**August 25**~~November 13, 2014	~~**FERC issued letter order to modify VSLs for Requirement R1.**~~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(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

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[1]	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[1] 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**[1]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack
	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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) **Note:** Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS.	12 calendar years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5 and Table 3, 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 and Table 3 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	Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

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).

Segment – *Protection Systems or 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.*

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 and Table 3 which requires corrective action, or a 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 configuration errors, or Protection System application errors are not included in Countable Events.*

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 of the Protection System Component population, 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 and Table 3 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 Protection System 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.
5. If the Components in a Protection System 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.

Application Guidelines

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 4.2.5

In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

Rationale for 4.2.6:

Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

A. Introduction

1. **Title:** **Protection System and Automatic Reclosing Maintenance**

2. **Number:** PRC-005-3(i)

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing 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 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 Special Protection System (SPS) for BES reliability.

4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:

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 for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems 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 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 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 100 kV or above.

4.2.7 Automatic Reclosing[1], 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.

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 SPS specified in Section 4.2.4.

5. Effective Date: See Implementation Plan.

6. Definitions Used in this Standard: The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing 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 – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

Component – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

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, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed

[1] 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 BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[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 and Automatic Reclosing 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 and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing 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, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing 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 and Automatic Reclosing 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, and Table 4-1 through 4-2. (Part 1.2)

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.

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 and Automatic Reclosing 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.

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 Protection System Maintenance Program for the Protection System and Automatic Reclosing 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.

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.

D. 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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, 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.

Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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 responsible 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)	The responsible 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). OR The responsible 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, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible 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). OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
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
2	October 17, 2013	Adopted by NERC Board of Trustees	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
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(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
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

<table>
<tr><th colspan="3">Table 1-1
Component Type - Protective Relay
Excluding distributed UFLS and distributed UVLS (see Table 3)</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval[2]</th><th>Maintenance Activities</th></tr>
<tr><td>Any unmonitored protective relay not having all the monitoring attributes of a category below.</td><td>6 Calendar Years</td><td>For all unmonitored relays:
• Verify that settings are as specified
For non-microprocessor relays:
• Test and, if necessary calibrate
For microprocessor relays:
• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.
• Verify acceptable measurement of power system input values.</td></tr>
<tr><td>Monitored microprocessor protective relay with the following:
• Internal self-diagnosis and alarming (see Table 2).
• 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.
• Alarming for power supply failure (see Table 2).</td><td>12 Calendar Years</td><td>Verify:
• Settings are as specified.
• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.
• Acceptable measurement of power system input values.</td></tr>
</table>

[2] 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[2]**	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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>
<tr><th colspan="3">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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="3">Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
• Station dc supply voltage
Inspect:
• For unintentional grounds</td></tr>
<tr><td>6 Calendar Months</td><td>Inspect:
• Condition of all individual units by measuring battery cell/unit internal ohmic values.</td></tr>
<tr><td>18 Calendar Months</td><td>Verify:
• Float voltage of battery charger
• Battery continuity
• Battery terminal connection resistance
• Battery intercell or unit-to-unit connection resistance
Inspect:
• Physical condition of battery rack</td></tr>
</table>

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, 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, and Tables 4-1 through 4-2 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	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 4-1
Maintenance Activities and Intervals for Automatic Reclosing Components
Component Type – Reclosing Relay

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	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 SPS 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 Relays that ARE an Integral Part of an SPS

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 SPS (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 SPS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the SPS.
Control circuitry associated with Automatic Reclosing that is an integral part of an SPS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

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, and Tables 4-1 through 4-2 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.
5. 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.

Application Guidelines

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 4.2.5:
In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

Rationale for 4.2.6:
Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

A. Introduction

1. **Title:** **Protection System and Automatic Reclosing Maintenance**

2. **Number:** PRC-005-3(i)

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing 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 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 Special Protection System (SPS) for BES reliability.

4.2.5 Protection Systems for the following BES generator Facilities ~~that are part~~for generators not identified through Inclusion I4 of the BES~~, including:~~ definition:

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 for generator step-up transformers for generators that are part of the BES.

The only revisions made to this version of PRC-005 are revisions to section 4.2, 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.

This version is labeled PRC-005-3(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-005 are in development to reflect the fact that applicability changes need apply for versions of the standard that are approved (PRC-005-2), pending regulatory approval (PRC-005-3), and in development in Project 2007-17.3.

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

~~4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).~~

~~4.2.5.4~~4.2.5.3 Protection Systems 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 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 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 100 kV or above.

Rationale for 4.2.6: Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

~~4.2.6~~4.2.7 Automatic Reclosing[1], including:

~~4.2.6.1~~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.

~~4.2.6.2~~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.~~6~~7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

[1] Automatic Reclosing addressed in Section 4.2.~~6~~7.1 and 4.2.~~6~~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 BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

~~4.2.6.3~~4.2.7.3 Automatic Reclosing applied as an integral part of an SPS specified in Section 4.2.4.

5. Effective Date: See Implementation Plan.

6. Definitions Used in this Standard: The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing 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 – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

Component – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

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, and Tables 4-1 through 4-2 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 or Automatic Reclosing configuration or application errors are not included in Countable Events.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[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 and Automatic Reclosing 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 and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing 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, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing 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 and Automatic Reclosing 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, and Table 4-1 through 4-2. (Part 1.2)

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.

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 and Automatic Reclosing 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.

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 Protection System Maintenance Program for the Protection System and Automatic Reclosing 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.

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.

D. 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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, 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.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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) OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)	The responsible 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)	The responsible 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). OR The responsible 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, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible 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).
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by 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
2	October 17, 2013	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	
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(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.
3(i)	November 13, 2014	Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[2]	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[2] 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**[2]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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>
<tr><th colspan="3">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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="2">Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
• Station dc supply voltage
Inspect:
• Electrolyte level
• For unintentional grounds</td></tr>
<tr><td>18 Calendar Months</td><td>Verify:
• Float voltage of battery charger
• Battery continuity
• Battery terminal connection resistance
• Battery intercell or unit-to-unit connection resistance
Inspect:
• 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
• Physical condition of battery rack</td></tr>
</table>

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, 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, and Tables 4-1 through 4-2 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	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

<table>
<tr><th colspan="3">Table 4-1
Maintenance Activities and Intervals for Automatic Reclosing Components
Component Type – Reclosing Relay</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td>Any unmonitored reclosing relay not having all the monitoring attributes of a category below.</td><td>6 Calendar Years</td><td>Verify that settings are as specified.
For non-microprocessor relays:
• Test and, if necessary calibrate
For microprocessor relays:
• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</td></tr>
<tr><td>Monitored microprocessor reclosing relay with the following:
• Internal self diagnosis and alarming (See Table 2).
• Alarming for power supply failure (See Table 2).</td><td>12 Calendar Years</td><td>Verify:
• Settings are as specified.
• Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</td></tr>
</table>

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	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 SPS 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 Relays that ARE an Integral Part of an SPS		
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 SPS (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 SPS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the SPS.
Control circuitry associated with Automatic Reclosing that is an integral part of an SPS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

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, and Tables 4-1 through 4-2 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.
5. 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.

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Generator Operator
   - **4.2.** Generator Owner
5. **Effective Dates**

   See Implementation Plan.

B. Requirements and Measures

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within each generating Facility's capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.
[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.
[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.
[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in Requirement R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

5.1. For generator step-up and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

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 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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

<table>
<tr><th rowspan="2">R #</th><th rowspan="2">Time Horizon</th><th rowspan="2">VRF</th><th colspan="4">Violation Severity Levels</th></tr>
<tr><th>Lower VSL</th><th>Moderate VSL</th><th>High VSL</th><th>Severe VSL</th></tr>
<tr><td>R1</td><td>Real-time Operations</td><td>Medium</td><td>N/A</td><td>N/A</td><td>N/A</td><td>Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.</td></tr>
<tr><td>R2</td><td>Real-time Operations</td><td>Medium</td><td>N/A</td><td>N/A</td><td>The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.</td><td>The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator.

OR

The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage.

OR

The Generator Operator did not modify voltage when directed, and the</td></tr>
</table>

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator’s specifications.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.	Revised
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised
3	5/7/2014	Adopted by NERC Board of Trustees	
3	8/1/2014	Approved by FERC in docket RD14-11-000	
4	8/27/2014	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised

4	11/13/2014	Adopted by NERC Board of Trustees	

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:

This requirement has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in either voltage controlling mode or the mode instructed by the TOP. However, the requirement has been modified to allow for testing, and the measure has been updated to include some of the evidence that can be used for compliance purposes.

Rationale for R2:

Requirement R2 details how a Generator Operator (GOP) operates its generator(s) to provide voltage support and when the GOP is expected to notify the Transmission Operator (TOP). In an effort to remove prescriptive notification requirements for the entire continent, the VAR-002-3 standard drafting team (SDT) opted to allow each TOP to determine the notification requirements for each of its respective GOPs based on system requirements. Additionally, a new Part 2.3 has been added to detail that each GOP may monitor voltage by using its existing facility equipment.

Conversion Methodology: There are many ways to convert the voltage schedule from one voltage level to another. Some entities may choose to develop voltage regulation curves for their transformers; others may choose to do a straight ratio conversion; others may choose an entirely different methodology. All of these methods have technical challenges, but the studies performed by the TOP, which consider N-1 and credible N-2 contingencies, should compensate for the error introduced by these methodologies, and the TOP possesses the authority to direct the GOP to modify its output if its performance is not satisfactory. During a significant system event, such as a voltage collapse, even a generation unit in automatic voltage control that controls based on the low-side of the generator step-up transformer should see the event on the low-side of the generator step-up transformer and respond accordingly.

Voltage Schedule Tolerances: The bandwidth that accompanies the voltage target in a voltage schedule should reflect the anticipated fluctuation in voltage at the GOP'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 GOP's AVR control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R3:

This requirement has been modified to limit the notifications required when an AVR goes out of service and quickly comes back in service. Notifications of this type of status change provide little to no benefit to reliability. Thirty (30) minutes have been built into the requirement to allow a GOP time to resolve an issue before having to notify the TOP of a status change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change.

Rationale for R4:

This requirement has been bifurcated from the prior version VAR-002-2b Requirement R3. This requirement allows GOPs to report reactive capability changes after they are made aware of the change. The current standard requires notification as soon as the change occurs, but many GOPs are not aware of a reactive capability change until it has taken place.

Rationale for Exclusion in R4:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide Real-time data as directed by the TOP.

Rationale for R5:

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected. The prior version of VAR-002-2b, Requirement R4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed. The percentage information was not needed because the tap settings, ranges and impedance are required. Those inputs can be used to calculate the step-change percentage if needed.

Rationale for Exclusion in R5:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR- 002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

Rationale for R6:

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-3. The standard was approved by FERC and became effective October 1, 2014. The intent of the revisions is to clarify application of Requirements R4 and R5 to Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
Board of Trustees adoption	November 2014

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
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4	11/13/2014	Adopted by NERC Board of Trustees	

Definitions of Terms Used in the Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

When this standard has received ballot approval, the text boxes within the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-~~3~~4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Generator Operator
   - **4.2.** Generator Owner

The only revisions made to this version of VAR-002 are revisions to Requirements R4 and R5, 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.

The revisions to the two Requirements were made to VAR-002-3, which was approved by its ballot pool and adopted by the NERC Board in May 2014, and was subsequently approved by FERC and became effective October 1, 2014.

5. **Effective Dates**

~~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, VAR-002-3 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.~~

See Implementation Plan.

B. Requirements and Measures

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,~~[1] shutdown,[2]~~,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule~~[3]~~[3] (within each generating Facility's capabilities[4]~~)~~[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the

~~[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.~~

~~[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.~~

~~[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.~~

~~[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.~~

generator is prepared for continuous operation.

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[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

~~2.1.~~2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

~~2.2.~~2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in Requirement R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for Exclusion in Requirement R4:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide Real-time data as directed by the TOP.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

5.1. For generator step-up ~~transformers~~ and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

Rationale for Exclusion in Requirement R5:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR-002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up ~~transformers~~ and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

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 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the-

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications. ~~OR~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~1~~	~~5/1/2006~~	~~Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.~~	~~July 5, 2006~~
~~1a~~	~~12/19/2007~~	~~Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007~~	~~Revised~~
~~1a~~	~~1/16/2007~~	~~In Section A.2., Added "a" to end of standard number.~~ ~~Section F: added "1."; and added date.~~	~~Errata~~
~~1.1a~~	~~10/29/2008~~	~~BOT adopted errata changes; updated version number to "1.1a"~~	~~Errata~~
~~1.1b~~	~~3/3/2009~~	~~Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009~~	~~Revised~~
~~2b~~	~~8/16/2012~~	~~Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b. Adopted by Board of Trustees.~~	~~Revised~~
~~2b~~	~~4/16/2013~~	~~FERC Order issued approving VAR-002-2b~~	
~~3~~	~~5/6/2014~~	~~Adopted by the NERC Board of Trustees~~	
~~3~~	~~8/1/2014~~	~~FERC issued letter order approving VAR-002-3~~	

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:

This requirement has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in either voltage controlling mode or the mode instructed by the TOP. However, the requirement has been modified to allow for testing, and the measure has been updated to include some of the evidence that can be used for compliance purposes.

Rationale for R2:

Requirement R2 details how a Generator Operator (GOP) operates its generator(s) to provide voltage support and when the GOP is expected to notify the Transmission Operator (TOP). In an effort to remove prescriptive notification requirements for the entire continent, the VAR-002-3 standard drafting team (SDT) opted to allow each TOP to determine the notification requirements for each of its respective GOPs based on system requirements. Additionally, a new Part 2.3 has been added to detail that each GOP may monitor voltage by using its existing facility equipment.

Conversion Methodology: There are many ways to convert the voltage schedule from one voltage level to another. Some entities may choose to develop voltage regulation curves for their transformers; others may choose to do a straight ratio conversion; others may choose an entirely different methodology. All of these methods have technical challenges, but the studies performed by the TOP, which consider N-1 and credible N-2 contingencies, should compensate for the error introduced by these methodologies, and the TOP possesses the authority to direct the GOP to modify its output if its performance is not satisfactory. During a significant system event, such as a voltage collapse, even a generation unit in automatic voltage control that controls based on the low-side of the generator step-up transformer should see the event on the low-side of the generator step-up transformer and respond accordingly.

Voltage Schedule Tolerances: The bandwidth that accompanies the voltage target in a voltage schedule should reflect the anticipated fluctuation in voltage at the GOP'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 GOP's AVR control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R3:

This requirement has been modified to limit the notifications required when an AVR goes out of service and quickly comes back in service. Notifications of this type of status change provide little to no benefit to reliability. Thirty (30) minutes have been built into the requirement to allow a GOP time to resolve an issue before having to notify the TOP of a status change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change.

Rationale for R4:

This requirement has been bifurcated from the prior version VAR-002-2b Requirement R3. This requirement allows GOPs to report reactive capability changes after they are made aware of the change. The current standard requires notification as soon as the change occurs, but many GOPs are not aware of a reactive capability change until it has taken place.

Rationale for R5:

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected. The prior version of VAR-002-2b, Requirement R4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed. The percentage information was not needed because the tap settings, ranges and impedance are required. Those inputs can be used to calculate the step-change percentage if needed.

Rationale for R6:

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected.

Exhibit B

Implementation Plans

NERC
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Implementation Plan

Dispersed Generation Resources
PRC-004-2.1(i)a

Standards Involved
Approval:

- PRC-004-2.1(i)a– Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-2.1a – Protection System Misoperation Identification and Correction

Prerequisite Approvals:
N/A

Background
In light of the adoption of a revised Bulk Electric System definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised Bulk Electric System definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

General Considerations
PRC-004-2.1(i)a is proposed for approval to align the applicability section of PRC-004-2.1a with the revised definition of Bulk Electric System. Given the timing of concurrent standards development of PRC projects, PRC-004-2.1a may already be retired pursuant to an Implementation Plan of a successor version of PRC-004 by the time the revised definition of Bulk Electric System becomes effective for all entities. If this occurs, PRC-004-2.1(i)a will not go into effect.

Effective Date
PRC-004-2.1(i)a shall become effective immediately after 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.

Retirement of Existing Standards:

The existing standard, PRC-004-2.1a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-2.1(i)a.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Implementation Plan

Dispersed Generation Resources
PRC-004-4

Standards Involved
Approval:

- PRC-004-4 – Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-3 – Protection System Misoperation Identification and Correction

Prerequisite Approvals:

- PRC-004-3 – Protection System Misoperation Identification and Correction[1]

Background
In light of the adoption of a revised Bulk Electric System definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised Bulk Electric System definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

General Considerations
PRC-004-4 is proposed for approval to align the applicability section of PRC-004-3 with the revised definition of the Bulk Electric System. The intent of the SDT was to allow for flexibility of the PRC-004 applicability section regardless of the version that is currently in effect when an applicable governmental authority acts on the PRC-004-3 filing. Currently, PRC-004-2.1a is in effect as PRC-004-3 (developed in Project 2010-05.1) is pending regulatory approval. Depending on the timing of approvals for various versions of PRC-004, PRC-004-2.1a may still be in effect at the time the revised definition of Bulk Electric System becomes effective for all entities. If this occurs, PRC-004-2.1(i)a will go into effect and PRC-004-4 shall go into effect after the technical revisions developed in Project 2010-05.1 are approved by applicable regulators, or as otherwise provided for in jurisdictions that do not require regulatory approvals.

[1] PRC-004-3 was adopted by the NERC Board of Trustees on August 18, 2014.

Effective Date

PRC-004-4 shall become effective on the later of the effective date of PRC-004-3, or the date that PRC-004-4 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 either 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, or 12 months following the effective date of PRC-004-3, whichever is later.

Retirement of Existing Standards:

The existing standard, PRC-004-3, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-4.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

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Implementation Plan

Project 2014-01 Standards Applicability for Dispersed Power Producing Resources
PRC-005-2(i)

Standards Involved
Approval:

- PRC-005-2(i) – Protection System Maintenance

Retirement:

- PRC-005-2 – Protection System Maintenance

Prerequisite Approvals:
N/A

Background:
In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

Reliability Standard PRC-005-2, with its associated Implementation Plan, was adopted by the NERC Board of Trustees on November 7, 2012. The SDT has revised the applicability section of PRC-005-2 to align with the revised definition of "Bulk Electric System" in the event that this version of PRC-005 is mandatory and enforceable on the effective date of the revised definition of "Bulk Electric System."

General Considerations:
PRC-005-2(i) is proposed for approval to align the applicability section of PRC-005-2 with the revised definition of "Bulk Electric System." PRC-005-2 may already be retired pursuant to an implementation plan of a successor version of PRC-005 by the time the revised definition of "Bulk Electric System" becomes effective. If this occurs, PRC-005-2(i) will not go into effect.

Effective Date

PRC-005-2(i) shall become effective on the later of the effective date of the revised definition of Bulk Electric System or the first day following the effective date of PRC-005-2.

Retirement of Existing Standards:

PRC-005-2 shall be retired at midnight of the day immediately prior to the effective date of PRC-005-2(i) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

All aspects of the Implementation Plan for PRC-005-2 will remain applicable to PRC-005-2(i) and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-005-2 is available here.

Implementation Plan

Project 2014-01 Standards Applicability for Dispersed Power Producing Resources
PRC-005-3(i)

Standards Involved

Approval:

- PRC-005-3(i) – Protection System and Automatic Reclosing Maintenance

Retirement:

- PRC-005-2(i) – Protection System Maintenance
- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Prerequisite Approvals

N/A

Background

In light of the adoption of a revised “Bulk Electric System” definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised “Bulk Electric System” definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

Reliability Standard PRC-005-3, with its associated Implementation Plan, was adopted by the NERC Board of Trustees on November 7, 2013. The SDT has revised the applicability section of PRC-005-3 to align with the revised definition of “Bulk Electric System” in the event that this version of PRC-005 is mandatory and enforceable on the effective date of the revised definition of “Bulk Electric System.”

General Considerations

PRC-005-3(i) is proposed for approval to align the applicability section of PRC-005-3 with the revised definition of “Bulk Electric System.” PRC-005-3 may already be retired pursuant to an Implementation Plan of a successor version of PRC-005 by the time the revised definition of “Bulk Electric System” becomes effective. If this occurs, PRC-005-3(i) will not go into effect.

Effective Date

PRC-005-3(i) shall become effective on the later of the effective date of the revised definition of Bulk Electric System or the first day following the effective date of PRC-005-3.

Retirement of Existing Standards

PRC-005-3 shall be retired at midnight of the day immediately prior to the effective date of PRC-005-3(i) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

PRC-005-3(i) only modifies the applicability for PRC-005-3. All aspects of the Implementation Plan for PRC-005-3 will remain applicable to PRC-005-3(i) and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-005-3 is available here.

Exhibit C

Draft Technical White Paper

Draft White Paper

Proposed Revisions to the Applicability of NERC Reliability Standards to Dispersed Generation Resources

Project 2014-01 Standards Applicability for Dispersed Generation Resources Standard Drafting Team

February 2, 2015

Table of Contents

1 Executive Summary

The purpose of this White Paper is to provide background and technical rationale for proposed revisions to the applicability of several North American Electric Reliability Corporation (NERC) Reliability Standards, and in some cases the standard requirements. The goal of the NERC Project 2014-01 Standards Applicability for Dispersed Generation Resources[1] standard drafting team (SDT) is to ensure that the Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System (BPS), as the characteristics of operating dispersed power producing resources can be unique. In light of the revised Bulk Electric System (BES) definition approved by the Federal Energy Regulatory Authority (FERC) in 2014[2], the intent of this effort is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources where the status quo does not create a reliability gap.

The SDT reviewed all standards that apply to GOs and GOPs[3] and determined how each standard requirement should be appropriately applied to dispersed power producing resources, categorized as follows:

- The existing standard language was appropriate when applied to dispersed power producing resources and does not need to be addressed;
- The existing standard language was appropriate when applied to dispersed power producing resources but additional NERC guidance documentation is needed to clarify how to implement the requirements for dispersed power producing resources; and
- The existing standard language needs to be modified in order to account for the unique characteristics of dispersed power producing resources. This could be accomplished through the Applicability Section of the standard in most cases or, if required, through narrowly-tailored changes to the individual requirements.

From this review, the SDT determined that three (3) Reliability Standards required immediate attention to clarify the applicability of the Reliability Standards to dispersed power producing resources for the benefit of industry stakeholders. These standards are:

- PRC-004 (relevant versions)[4];
- PRC-005 (relevant versions)[5]; and
- VAR-002 (relevant versions).

The SDT recognized that many other standards[6] required further review to determine the necessity and the type of clarification or guidance for the applicability to dispersed power producing resources. This

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[1] Although the BES definition uses the term "dispersed power producing resources," the SAR and the SDT also use the term "dispersed generation resources." For the purposes of this paper, these terms are interchangeable.
[2] Glossary of Terms Used in NERC Reliability Standards, updated March 12, 2014.
[3] See Appendix A.
[4] Reliability Standard PRC-004 was revised as part of Project 2010-05.1 Protection Systems: Misoperations.
[5] Reliability Standard PRC-005 was revised as part of Project 2007-17.3 – Protection System Maintenance and Testing – Phase 3.
[6] See Appendix B.

necessity is based on how each standard requirement, as written, would apply to dispersed power producing resources and the individual generating units at these facilities, considering the now currently-enforced BES definition. The proposed resolutions target the applicability of the standard or target specific individual requirements. There are additional methods to ensure consistent applicability throughout the Regions, including having guidance issued by NERC through Reliability Standard Audit Worksheet (RSAW) language revisions. These tools, among others, have been considered and employed by the SDT throughout the drafting effort.

The White Paper includes: 1) description of the history of standards applicability to dispersed power producing resources; 2) identification of circumstances and practices that are unique to dispersed power producing resources; and 3) determination of the priority to address standards, supported by corresponding technical justification.

It is the intent of the SDT to modify this document over the course of this project to document the SDT's rationale and technical justification for each standard until the work of the SDT is complete. The SDT considers the sections of the White Paper that address the high-priority standards to be in final draft form. The SDT may provide further revisions to the remainder of the White Paper.

2 Purpose

The purpose of this White Paper is to provide background and technical rationale for proposed revisions to the applicability of several Reliability Standards[7] or requirements that apply to GOs and/or GOPs. The goal of the proposed applicability changes is to provide the GOs and GOPs of dispersed generation resources with clarity regarding their responsibility for requirements that impact the reliability of the BPS, as the characteristics of operating dispersed generation can be unique. The SDT seeks to provide clarity through the method most appropriate for each standard, such as by: (1) revising applicability language in the standard; (2) revising language in the requirements to address changes to applicability; (3) recommending changes to the RSAW associated with the standard; or (4) recommending a reliability guideline or reference document.

This document describes the design, operational characteristics, and unique features of dispersed power producing resources. The recommendations identified in this document consider the Purpose and Time Horizon of the standards and requirements, as well as the avoidance of applying requirements in a manner that has no significant effect on reliability.[8] This document provides justification of, and proposes revisions to, the applicability of the Reliability Standards and requirements, both existing and in development, and should be considered guidance for future standard development efforts. However, please note that the recommendations provided in this paper are subject to further review and revision.

Note that while this White Paper may provide examples of dispersed power producing resources, the concepts presented are not specific to any one technology. The SDT in general has referenced the BES Reference Document, which also refers to "dispersed power producing resources." Although the BES definition uses the term "dispersed power producing resources," the Standard Authorization Request (SAR) and the SDT also use the term "dispersed generation resources." For the purposes of this paper, these terms are interchangeable.

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[7] Note that "Reliability Standard" is defined in the NERC Glossary as "approved by FERC," but that the SDT reviewed approved standards, as well as revisions to standards proposed in other projects.

[8] *North American Electric Reliability Corporation*, 138 FERC ¶ 61,193 at P 81 (2012).

3 Background

Industry stakeholders submitted a SAR to the NERC Standards Committee, requesting that the applicability of Reliability Standards or the requirements of Reliability Standards be revised to ensure that the Reliability Standards are not imposing requirements on dispersed generation resource components that are unnecessary or counterproductive to the reliability of the BPS. The SDT's focus has been to ensure that Reliability Standards are applied to dispersed power producing resources to support an effective defense-in-depth strategy and an adequate level of reliability for the interconnected BPS.

For purposes of this effort, dispersed power producing resources are those individual 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. This request is related to the approved definition of the BES from Project 2010-17,[9] which resulted in the inclusion of distinct components of dispersed generation resources.

3.1 BES Definition

The BES definition[10] includes the following inclusion criterion addressing dispersed generation resources:

> *I4. 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. Thus, the facilities designated as BES are:*
>
> > *a) The individual resources, and*
> > *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.*

The *BES Definition Reference Document*[11] includes a description of what constitutes dispersed generation resource:

> *"Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to: solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells."*

[9] http://www.nerc.com/pa/Stand/Pages/Project2010-17_BES.aspx
[10] Glossary of Terms Used in NERC Reliability Standards, updated March 12, 2014. http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
[11] Bulk Electric System Definition Reference Document, Version 2, April 2014. http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_reference_document_20140325_final_clean.pdf.

3.2 Dispersed Power Producing Resources

Dispersed power producing resources are often considered to be variable energy resources such as wind and solar. This description is not explicitly stated in the BES definition; however, NERC and FERC characterize variable generation in this manner regarding the purpose of Inclusion I4 of the definition.[12].Therefore, the SDT is considering the reliability impacts of variable generation that depends on a primary fuel source which varies over time and cannot be stored.[13] Reliably integrating high levels of variable resources – wind, solar, ocean, and some forms of hydro – into the BPS require significant changes to traditional methods used for system planning and operation.[14] While these resources provide challenges to system operation, these resources are instrumental in meeting government-established renewable portfolio standards and requirements that are based on vital public interests.[15]

3.2.1 Design Characteristics

For dispersed power producing resources to be economically viable, it is necessary for the equipment to be geographically dispersed. The generating capacity of individual generating modules can be as small as a few hundred watts to as large as several megawatts. Factors leading to this dispersion requirement include:

- Practical maximum size for wind generators to be transported and installed at a height above ground to optimally utilize the available wind resource;
- Spacing of wind generators geographically to avoid interference between units;
- Solar panel conversion efficiency and solar resource concentration to obtain usable output; and
- Cost-effective transformation and transmission of electricity.

The utilization of small generating units results in a large number of units (e.g., several hundred wind generators or several million solar panels) installed collectively as a single facility that is connected to the Transmission system.

Dispersed power producing resources interconnected to the transmission system typically have a control system at the group level that controls voltage and power output of the Facility. The control system is capable of recognizing the capability of each individual unit or inverter to appropriately distribute the contribution required of the Facility across the available units or inverters. The variable generation control system must also recognize and account for the variation of uncontrollable factors such as wind speed and solar irradiance levels. Thus, for some standards discussed in this paper it is appropriate to apply requirements at the plant level rather than the individual generating unit.

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[12] NERC December 13, 2013 filing, page 15 (FERC Docket No. RD14-2); NERC December 13, 2013 filing, page 17 (FERC Docket No. RD14-2); NERC January 25, 2012 filing, page 18 (FERC Docket No. RD14-2), FERC Order Approving Revised Definition, Docket No. RD14-2-000, Issued March 20, 2014.

[13] "*Electricity Markets and Variable Generation Integration*," WECC, January 6, 2011.

[14] "*Accommodating High Levels of Variable Generation*," NERC, April, 2009. http://www.nerc.com/files/ivgtf_report_041609.pdf

[15] *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 335, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

3.2.2 Operational Characteristics

Dispersed power producing resources often rely on a variable energy source (wind, for example) that is not able to be stored. Because of this, a Facility operator cannot provide a precise forecast of the expected output to a Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC); however, short-term forecasting capability is improving and thus reducing uncertainty.[16] The forecasting and variable operating conditions are well understood by BAs, TOPs, and RCs as evidenced by the successful operation of these generating resources over the years. Dispersed generation resources by their nature result in each individual generating unit potentially experiencing varied power system parameters (e.g. voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities design.

Many older dispersed power producing resources are limited in their ability to provide essential reliability services. However, due to technological improvements, newer dispersed generation resources are capable of providing system support for voltage and frequency. For efficiency, the facilities are designed to provide the system requirements at the point of interconnection to the transmission system.

3.2.3 Reliability Impact

A dispersed power producing resource is typically made up of many individual generating units. In most cases, the individual generating units are similar in design and from one manufacturer. The aggregated capability of the Facility may in some cases contribute significantly to the reliability of the BPS. As such, there can be reliability benefits from ensuring the equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in certain applicable NERC standards. When evaluated individually, however, the individual generating units often do not provide a significant impact to BPS reliability, as the unavailability or failure of any one individual generating resource may have a negligible impact on the aggregated capability of the Facility. The SDT acknowledges that FERC addressed the question of whether individual resources should be included in the BES definition in Order Nos. 773 and 773-A and concluded that individual wind turbine generators should be included as part of the BES. The SDT is not challenging this conclusion, but rather is addressing the applicability of standards on a requirement-by-requirement basis as necessary to account for the unique characteristics of dispersed generation. Thus, the applicability of requirements to individual generating units may be unnecessary except in cases where a common mode issue exists that could lead to a loss of a significant number of units or the entire Facility in response to a transmission system event.

3.3 Drafting Team Efforts

The SDT approached this project in multiple phases. First, after a thorough discussion of the new definition of the BES, the SDT reviewed each standard, as shown in Appendix A, at a high level to recommend changes that would promote consistent applicability for dispersed power producing resources through the entire set of Reliability Standards. This review provided the type of changes proposed, the justification for the changes, and the priority of the changes. The SDT documented its review in this

[16] "*Electricity Markets and Variable Generation Integration*," WECC, January 6, 2011. https://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/WECC%20Whitepaper%20-%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf

White Paper, which will continue to be updated throughout the SDT efforts. The second phase, currently in progress, includes revising standards where necessary and supporting the balloting and commenting process.

3.3.1 Scope of Standards Reviewed

Initially, the focus of the standards review was on standards and requirements applicable to GOs and GOPs. However, during discussions, a question was raised to the SDT whether consideration is necessary for other requirements that affect the interaction of a Balancing Authority (BA), Transmission Operator (TOP), or Reliability Coordinator (RC) with individual BES Elements. For example, a requirement that states "an RC shall monitor BES Elements" may unintentionally affect the RC operator due to the revised BES definition. As such, the SDT took a high-level look at all standards adopted by the NERC Board of Trustees (Board) or approved by FERC to ensure this issue was not significant.

All standards that were reviewed are listed in Appendix A along with the status of the standards as of December 11, 2014. The fields in Appendix A include the following:

- List of standards (grouped by approval status)
- Approval status of the standards which include
  - Subject to Enforcement
  - Subject to Future Enforcement
  - Filed and Pending Regulatory Approval
  - Pending Regulatory Filing
  - Designated for Retirement (2 standards – MOD-024-1 and MOD-025-1 – officially listed as Filed and Pending Regulatory Approval but will be superseded by MOD-025-2)
  - In concurrent active development
- Indication of change or additional review necessary

The SDT also reviewed, at a high-level, any approved regional standards. In cases where a change is recommended to a regional standard, the SDT will notify the affected Region. In addition, the SDT is prepared to provide recommendations to other active NERC standard development efforts, where appropriate.

Status	Number of Standards	Number of Standards to be Addressed (Standard, RSAW, Guidance or Further Review)
NERC Standards	**166**	**27**
Subject to Enforcement	101	12
Subject to Future Enforcement	20	5
Pending Regulatory Approval	28	4
Pending Regulatory Filing	7	0
Designated for Retirement	2	0
Proposed for Remand	8	6
Region-specific Standards (*Out of Scope)	**17**	**4**
Subject to Enforcement	15	3
Subject to Future Enforcement	2	1
Pending Regulatory Approval	0	0
Grand Total	**183**	**31**

3.3.2 Reliability Objectives

The SDT used the following Reliability Objectives to review the standards:

- Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
- The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
- Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
- Plans for Emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
- Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
- Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
- The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
- Bulk power systems shall be protected from malicious physical or cyber attacks.

3.3.3 Prioritization Methodology

The SDT established a prioritization to review and modify applicability changes recommended to NERC standards and requirements. The SDT evaluated each requirement to identify the appropriate applicability to support reliability of the BPS. In general, any standard or requirement the SDT determined required modification was assigned a high, medium, or low priority. The standards and requirements priorities were established as follows:

- High priority was assigned so that standard or requirement changes would be made quickly enough to avoid an entity having to expend inordinate resources prematurely to comply with a standard or requirement that, after appropriate modification, would not be applicable to that entity.
- Medium priority was assigned if significant effort and resources with no appreciable reliability benefit would be required by an entity to be compliant; and
- Low priority was assigned to other changes that may need to be made to further ensure requirements add to reliability, but are not perceived as a significant compliance burden.

The prioritization of each recommendation is identified in Appendix B.

- List of standards (grouped by priority)
- Approval status of the standards (same designations as used in Appendix A)
- Recommendation of changing the Applicability Section of the standard or by changing the applicability for specific requirements
- Recommendation of which applicability options should apply.

4 Technical Discussion

This section provides a review of each group of standards, focusing on the impact of the BES definition on reliability and compliance efforts. This discussion proposes a resolution for each standard, whether it is a change in the Applicability Section or in a specific requirement, clarification in a guidance document, or no action needed.

4.1 BAL

The group of BAL standards focuses primarily on ensuring the Balancing Authority (BA) has the awareness, ability, and authority to maintain the frequency and operating conditions within its BA Area. Only two standards in this group affect GO and/or GOP, and no BAL standard reviewed affected the interaction of a host BA, TOP, or RC with individual BES Elements.

4.1.1 BAL-005 — Automatic Generation Control

The purpose of this standard, as it applies to GOPs, is to ensure that all facilities electrically synchronized to the Interconnection are included within the metered boundary of a BA Area so that balancing of resources and demand can be achieved. Ensuring the Facility as a whole is within a BA Area ensures the individual units are included. *Therefore, the applicability of the BAL-005 standard does not need to be changed for dispersed power producing resources.*

4.1.2 BAL-001-TRE-1 — Primary Frequency Response in the ERCOT Region

The purpose of BAL-001-TRE-1 standard is to maintain Interconnection steady-state frequency within defined limits. This standard should be modified to clarify the applicability for dispersed power producing resources to the total plant level to ensure coordinated performance. However, this is a regional standard and not part of the SDT scope. *The SDT will communicate this recommendation to the relevant Region.*

4.2 COM

The COM standards focus on communication between the RC, BAs, TOPs, and GOPs. The only requirements in any of the current or future enforceable standards that apply to the GOP are clearly intended to apply to the individual GOP registered functional entity (i.e., requires communication between GOPs, TOPs, BAs, and RCs), not the constituent Elements it operates. Consequently, there is no need to differentiate the GOPs obligation for dispersed power producing resources from any other resources. *Therefore, the applicability of the COM-001-2, COM-002-2a, and COM-002-4 standards that were reviewed do not need to be changed for dispersed power producing resources.*

4.3 EOP

The EOP standards focus on emergency operations and reporting. The standards that apply to GO and/or GOP entities are EOP-004 and EOP-005. No EOP standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

4.3.1 EOP-004 — Event Reporting

The purpose of this standard is to improve the reliability of the BES by requiring the reporting of events by Responsible Entities. The requirements of this standard that apply to the GO and GOP appear to apply to the individual GO and GOP registered functional entity, not the constituent elements. *The SDT has considered whether there is a need to differentiate dispersed power producing resources from any other GO and/or GOP resource and determined that no changes are required to the standard.*

4.3.2 EOP-005 — System Restoration from Blackstart Resources

EOP-005 ensures plans are in place to restore the grid from a de-energized state. The requirements that apply to a GOP are primarily for individual generation facilities designated as Blackstart Resources, with one requirement to participate in restoration exercises or simulations as requested by the RC. The inclusion of Blackstart Resources is already identified in the BES definition through Inclusion I3. The expectation is that all registered GOPs will participate in restoration exercises as requested by its RC. *Therefore, the applicability of EOP-005 does not need to be changed for dispersed power producing resources.*

4.4 FAC

The FAC standards focus on establishing ratings and limits of the Facility and interconnection requirements to the BES. Several standards apply to GOs and/or GOPs. No FAC standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

4.4.1 FAC-001 — Facility Connection Requirements

Requirements R2 and R3 of this standard apply to any GO that has an external party applying for interconnection to the GO's existing Facility in order to connect to the transmission system. This scenario is uncommon and there is no precedent for applicability of this standard to dispersed *power producing* resources known to the SDT. Current practice primarily includes the GO stating that they will comply with the standard if this scenario is ever realized. This standard allows the GO to specify the conditions that must be met for the interconnection of the third-party, thus providing inherent flexibility to tailor the requirements specifically for the unique needs of the Facility. *Therefore, the applicability of FAC-001 does not need to be changed for dispersed power producing resources.*

4.4.2 FAC-002 — Coordination of Plans for New Facilities

The purpose of FAC-002 is to ensure coordinated assessments of new facilities. The requirement applicable to GOs requires coordination and cooperation on assessments to demonstrate the impact of new facilities on the interconnected system and to demonstrate compliance with NERC standards and other applicable requirements. The methods used to demonstrate compliance are independent of the type of generation and are typically completed at the point of interconnection. *Therefore, the applicability of FAC-002 does not need to be changed for dispersed power producing resources.*

4.4.3 FAC-003 — Transmission Vegetation Management

The purpose of this standard is to ensure programs and efforts are in place to prevent vegetation-related outages. This standard applies equally to dispersed generation facilities and traditional Facilities in both applicability and current practices, as it pertains to overhead transmission lines of applicable generation interconnection Facilities. *Therefore, the applicability of FAC-003 does not need to be changed for dispersed power producing resources.*

4.4.4 FAC-008 — Facility Ratings

FAC-008 ensures Facility ratings used in the planning and operation of the BES are established and communicated. The Facility ratings requirement has historically been applicable to dispersed power producing resources and current practices associated with compliance are similar to traditional generation facilities. There is inherent flexibility in the standard requirements for the GO to determine the methodology utilized in determining the Facility ratings.

To identify the Facility rating of a dispersed power producing resource the analysis of the entire suite of Facility components is necessary to adequately identify the minimum and maximum Facility Rating and System Operating Limits, and thus there would be no differentiation between the compliance obligations between dispersed power producing resources and traditional generation. *The SDT believes the industry and Regions would benefit from additional guidance on FAC-008 in the form of changes to add a technical guidance section to the standard, or other guidance.*

4.5 INT

The INT standards provide BAs the authority to monitor power interchange between BA Areas. No INT standard is applicable to the GO or GOP, or affects the interaction of a host BA, TOP, or RC with individual BES Elements. *Therefore, the applicability of the INT standards do not need to be changed for dispersed power producing resources.*

4.6 IRO

The IRO standards provide RCs their authority. There are three IRO Standards that apply directly to GO and/or GOP entities. There are three standards that apply to the interaction of the RC with individual BES Elements. No other IRO standard reviewed affected the interaction of a host BA, TOP, or RC with GOs and/or GOPs.

4.6.1 IRO-001 — Reliability Coordination — Responsibilities and Authorities[17]

The purpose of these standards and their requirements as applicable to a GOP is to ensure RC directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements, or cannot be physically implemented. If a GOP is unable to follow a RC directive they are to inform the RC immediately of such.

Directives from RCs have been traditionally applied to the dispersed power producing resource at the aggregate Facility level when they are related to either active power or voltage, such as an output reduction or the provision of voltage support. When such directives are not specific to any one Element within the Facility, it is up to the GOP to determine the appropriate method to achieve the desired result of the directive consistent with other applicable NERC Reliability Standards. When an RC directive specifies a particular Element or Elements at the GOP's Facility, it is the expectation and requirement that the GOP will act as directed, so long as doing so does not violate safety, equipment, or regulatory or statutory requirements or cannot be physically implemented. For example, a directive could specify

[17] Note that IRO-001-3, which is adopted by the Board, was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

operation of a particular circuit breaker at a GOP Facility. *For these reasons, the applicability of IRO-001 does not need to be changed for dispersed power producing resources.*

4.6.2 IRO-005 — Reliability Coordination — Current Day Operations[18]

The purpose of this standard and its requirements as it relates to GOPs is to ensure when there is a difference in derived limits the BES is operated to the most limiting parameter. A difference in derived limits can occur on any Element and therefore any limitation of the applicability of this standard may create a reliability gap. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of IRO-005 does not need to be changed for dispersed power producing resources.*

4.6.3 IRO-010 — Reliability Coordinator Data Specification and Collection

The purpose of this standard and its requirement(s) as it relates to GOs and GOPs is to ensure data and information specified by the RC is provided. As each RC area is different in nature, up to and including the tools used to ensure the reliability of the BPS, a 'one size fits all' approach is not appropriate. This Reliability Standard allows for the RC to specify the data and information required from the GO and/or the GOP, based on what is required to support the reliability of the BPS. *Therefore, the applicability of IRO-010 does not need to be changed for dispersed power producing resources.*

4.7 MOD

The MOD group of standards ensures consistent modeling data requirements and reporting procedures. The MOD standards provide a path for Transmission Planners (TPs) and Planning Coordinators (PCs) to reach out to entities for specific modeling information, if required. The SDT believes the existing and proposed modeling standards are sufficient for modeling dispersed power producing resources. However, due to the unique nature of dispersed power producing resources and an effort to bring consistency to the models, *the SDT believes additional guidance on the MOD standards would be beneficial and will communicate its determination to the NERC Planning Committee.*

4.7.1 MOD-010 — Steady-State Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-010 does not need to be changed for dispersed generation resources.*

4.7.2 MOD-012 — Dynamics Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-012 does not need to be changed for dispersed generation resources.*

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[18] Note that applicability to GOPs has been removed in IRO-005-4, which is adopted by the Board. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

4.7.3 MOD-024-1 — Verification of Generator Gross and Net Real Power Capability

This standard was established to ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2.[19] *Therefore, the applicability of MOD-024-1 does not need to be changed for dispersed generation resources.*

4.7.4 MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability

This standard was established to ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2. *Therefore, the applicability of MOD-025-1 does not need to be changed for dispersed generation resources.*

4.7.5 MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net Real and Reactive Power capability is available for planning models used to assess BES reliability. This standard is appropriate for and includes specific provisions for dispersed generation resources to ensure changes in capabilities are reported. *Therefore, the SDT is further evaluating whether to revise the applicability of the standard to align the language with the revised BES definition.*

4.7.6 MOD-026 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

This standard provides for verification of models and data for voltage control functions. This standard is appropriate for dispersed generation resources. *Originally, the DGR SDT considered clarifying the applicability of the Facilities section, however, upon further review, the DGR SDT recommends no change.*

4.7.7 MOD-027 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

This standard was established to verify that the turbine/governor and frequency control model accurately represent generator unit Real Power response to system frequency variations. This standard is appropriate for dispersed generation resources. *Originally, the DGR SDT considered clarifying the applicability of the Facilities section, however, upon further review, the DGR SDT recommends no change.*

4.7.8 MOD-032 — Data for Power System Modeling and Analysis

The MOD-032 standard was established to ensure consistent modeling data requirements and reporting procedures for the planning horizon cases. The nature of dispersed generation resources is a challenge in modeling the steady-state and dynamic electrical properties of the individual components (e.g. individual units, collector system, interconnection components, etc.).

[19] MOD-024-1 and MOD-025-1 are Board Adopted but not subject to enforcement. They are commonly followed as good utility practice.

Models for dispersed power producing resources are typically proprietary and unique for each Facility. Generic models exist for dynamic analysis that may provide sufficient accuracy in lieu of a Facility-specific model. Some sections of the MOD-032 Attachment 1 pertain to modeling individual units, which may not be feasible. Guidance should be provided to show how to best model dispersed power producing resources. Such guidance should require modeling requirements for each type of dispersed power producing resource within a Facility and aggregate model for each reasonable aggregation point. *The applicability of MOD-032 does not need to be changed for dispersed power producing resources.*

4.8 NUC

The requirements in standard NUC-001 — *Nuclear Plant Interface Coordination* individually define the applicability to Registered Entities, not to the Elements the entities own or operate. While it is unlikely any Elements that are part of a dispersed power producing resource would be subject to an agreement required by this standard, limiting the applicability of this standard could create a reliability gap and thus, there is no need to differentiate applicability to dispersed generation resources. *Therefore, the applicability of the NUC standard does not need to be changed for dispersed power producing resources.*

4.9 PER

The PER standards focus on operator personnel training. The only requirements in any of the current or future enforceable standards that apply to the GOP is requirement R6 in PER-005-2 – *Operations Personnel Training,* and it is clearly intended to apply to the individual GOP registered functional entity that controls a fleet of generating facilities, not the constituent Elements it operates. As such, there is no need to differentiate dispersed power producing resources from any other GOP resources. *Therefore, the applicability of the PER standards do not need to be changed for dispersed power producing resources.*

4.10 PRC

The PRC standards establish guidance to ensure appropriate protection is established to protect the BES.

4.10.1 PRC-001-1.1 — System Protection Coordination

Requirement R1 requires GOPs to be familiar with the purpose and limitations of Protection System schemes applied in their area. The recently approved changes to the BES definition extend the applicability of this requirement. Often this familiarity is provided to GOP personnel through training on the basic concepts of relay protection and how it is utilized. The basic relaying concepts utilized in protection on the aggregating equipment at a dispersed generation site typically will not vary significantly from the concepts used in Protection Systems on individual generating units.

Requirement R2 requires that GOPs report protective relay or equipment failures that reduce system reliability. Protective System failures occurring within a single individual generating unit at a dispersed power producing resource will not have any impact on overall system reliability and thus it should not be necessary for GOPs to report these failures to their TOP and host BA. Only failures of Protection Systems on aggregating equipment have the potential to impact BPS reliability and may require notification. When interpreted as stated above, no related changes should be required to the existing PRC-001-1 standard, as the BES definition changes do not have an impact on these requirements.

Requirement R3 requires GOPs to coordinate new protective systems. Coordinating new and changes to existing protective relay schemes should be applied to aggregating equipment protection only if a lack of coordination could cause unintended operation or non-operation of an interconnected entity's protection, thus potentially having an adverse impact to the BPS. Existing industry practice is to share/coordinate the protective relay settings on the point of interconnect (e.g. generator leads, radial generator tie-line, etc.) and potentially the main step-up transformer, but not operating (collection) buses, collection feeder, or individual generator protection schemes, as these Protection Systems do not directly coordinate with an interconnected utility's own Protection Systems. Relay protection functions such as under and overfrequency and under and overvoltage changes are independent of the interconnected utility's protective relay settings and the setting criteria are defined in PRC-024.

Requirement R5 requires GOPs to coordinate changes in generation, transmission, load, or operating conditions that could require changes in the Protection Systems of others. A GOP of a dispersed generation resource should be required to notify its TOP of changes to generation, transmission, load, or operating conditions on an aggregate Facility level.

Project 2007-06 – System Protection Coordination and Project 2014-03 – Revisions to TOP and IRO Standards are presently revising various aspects of this standard or addressing certain requirements in other standards.

For these reasons, the DGR SDT coordinated with the other SDTs currently reviewing this standard and recommended revisions to Requirement R3.1 to indicate that coordination by a GOP with their TOP and host BA of new or changes to protection systems on individual generating units of dispersed power producing resources is not required.

4.10.2 PRC-001-2 — System Protection Coordination

The concerns addressed with PRC-001-1.1b are removed in PRC-001-2, which is adopted by the Board. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-03 – Revisions to TOP and IRO Standards. This Standard version is not in effect and was withdrawn as the proposed versions of the TOP and IRO Reliability Standards included in Project 2014-3 effectively replace PRC-001-2 and other TOP standards. *For this reason, no changes are required.*

4.10.3 PRC-002-NPCC-01— Disturbance Monitoring
PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting

Requirements related to installation of Fault/Disturbance monitoring and/or sequence of events (SOE) recording capabilities on generating units and substation equipment which meet regional specific criteria may require installation of these capabilities on the aggregating equipment at a dispersed power producing resource Facility, and also requires maintenance and periodic reporting requirements to their RRO. However, these requirements have been previously applicable to the aggregating equipment at these dispersed power producing resources, and these capabilities are not required to be installed on the individual generating units. The BES definition changes have no direct impact on applicability of these standards to dispersed power producing resources. *Therefore, the applicability of these standards do not need to be changed for dispersed power producing resources.*[20]

4.10.4 PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations
PRC-004-3 — Protection System Misoperation Identification and Correction

Misoperation reporting per PRC-004 is currently a requirement applied on the aggregating equipment at applicable dispersed power producing resource sites meeting BPS criteria. The continuation of this analysis and reporting on the aggregating equipment by dispersed generation resource owners can provide value to BPS reliability and should remain in place. However, based on the experience of the SDT, there is minimal impact to BPS reliability for analyzing, reporting and developing Corrective Action Plans for each individual generating unit that trips at a dispersed power producing resource site, as the tripping of one or a small number of these units has no material impact to the BPS reliability.

Additionally, reporting of Misoperations on each individual generating unit may result in substantial and unnecessary burdens on both the dispersed generation resource owner and the Regional Entities that review and track the resulting reports and Corrective Action Plan implementations. The SDT recognizes that many turbine technologies do not have the design capability of providing sufficient data for an entity to evaluate whether a Misoperation has occurred. Furthermore, dispersed power producingresources by their nature result in each individual generating unit potentially experiencing varied power system parameters (e.g., voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities design. This limits the ability to determine whether an individual unit correctly responded to a system disturbance.

However, the SDT maintains that 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 large number of the individual generation resources (aggregate nameplate rating of greater than 75 MVA) incorrectly operated or failed to operate as designed during a system event. As such, if a trip aggregating to greater than 75 MVA occurs in response to a system disturbance, the SDT proposed requiring analysis and reporting of Misoperations of individual generating units for which the root cause of the Protection System operation(s) affected an aggregate rating of greater than 75 MVA of BES Facilities. Note that the SDT selected the 75 MVA nameplate threshold for consistency and to prevent confusion.

The SDT was also concerned with the applicability of events where one or more individual units tripped and the root cause of the operations was identified as a setting error. In this case, the requirements of PRC-004 would be applicable for any individual units where identical settings were applied on the Protection Systems of like individual generation resources identified under Inclusion I4 of the BES definition.

The SDT concluded that it is not necessary under PRC-004 to analyze each individual Protection System Misoperation affecting individual generating units of a dispersed power producing resource. *The SDT*

[20] *See* NPCC CGS-005.

recommended changes to the applicability of this standard to require misoperation analysis on individual generating units at a dispersed power producing resource site, only for events affecting greater than 75MVA aggregate nameplate; the SDT determined that this will ensure that common mode failure scenarios and their potential impact on BPS reliability are appropriately addressed. The SDT's recommended changes passed industry ballot on November 6, 2014, and were approved by the Board on November 13, 2014, and are currently pending regulatory approval.

4.10.5 PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

Dispersed power producing resource sites typically would not be associated with a WECC Major Transfer Path or Remedial Action Scheme (RAS), and thus would not be affected by PRC-004-WECC-1. If a site were to be involved with one of these paths or schemes, it is likely that associated protection or RAS equipment would be located on the aggregating equipment rather than the individual generating units. As such, the BES definition changes may have an impact on applicability of this standard to dispersed power producing resources. This standard should be modified to clarify the applicability for dispersed generation resources; however, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.*

4.10.6 PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing

The SDT recognizes that PRC-005-1.1b will be phased out beginning in early 2015. Therefore, the SDT recommends only guidance on PRC-005-1.1b rather than suggesting language changes to the standard. *Therefore, the SDT does not recommend revising the applicability of this standard for dispersed generation resources, rather, the SDT provided recommendations for revisions to the applicable RSAW to NERC staff, which NERC has implemented after consultation with the Regions.*

4.10.7 PRC-005-2 — Protection System Maintenance
PRC-005-3 — Protection System and Automatic Reclosing Maintenance
PRC-005-4 — Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

The aggregated capability of the individual generating units may in some cases contribute to the reliability of the BPS; as such, there can be reliability benefit from ensuring certain BES equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in PRC-005. When evaluated individually, however, the generating units themselves do not have the same impact on BPS reliability as the system used to aggregate the units. The unavailability or failure of any one individual generating unit would have a negligible impact on the aggregated capability of the Facility; this would be irrespective to whether the dispersed generation resource became unavailable due to occurrence of a legitimate fault condition or due to a failure of a control system, protective element, dc supply, etc.

The protection typically utilized in these generating units includes elements which would automatically remove the individual unit from service for certain internal or external conditions, including an internal fault in the unit. These units typically are designed to provide generation output at low voltage levels, (i.e., less than 1000 V). Should these protection elements fail to remove the generating unit for this scenario, the impacts would be limited to the loss the individual generating unit and potentially the next device upstream in the collection system of the dispersed power producing resource. However, this would still only result in the loss of a portion of the aggregated capability of the Facility, which would be equally likely to occur due to a scenario in which a fault occurs on the collection system.

Internal faults on the low voltage system of these generating units would not be discernible on the interconnected transmission systems, as this is similar to a fault occurring on a typical utility distribution system fed from a substation designed to serve customer load. It is important to note that the collection system equipment (e.g., breakers, relays, etc.) used to aggregate the individual units may be relied upon to clear the fault condition in both of the above scenarios, which further justifies ensuring portions of the BES collection equipment is maintained appropriately.

For this reason, activities such as Protection System maintenance on each individual generating unit at a dispersed generation Facility would not provide any additional reliability benefits to the BPS, but Protection System maintenance on facilities where generation aggregates to 75 MVA or more would. The SDT proposes that the scope of PRC-005 be limited to include only the protection systems that operate at a point of aggregation above 75 MVA nameplate rating. If the aggregation point occurs at a component in the collection system, then the protection systems associated with this component would be in scope. *The SDT has recommended changes to the Applicability Section (Facilities) of PRC-005-2, -3, and -4 to indicate that maintenance activities should only apply on the aggregating equipment at or above the point where the aggregation exceeds 75 MVA. The SDT's recommended applicability changes to PRC-005-2 and PRC-005-3 were approved by the Board on November 13, 2014. The SDT's recommended applicability changes to PRC-005-4 were posted for an initial ballot period that ends on January 22, 2014.*

4.10.8 PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding
PRC-006-SERC -1 — Automatic Underfrequency Load Shedding Requirements

The regional specific PRC-006 standards deviate from the PRC-006-1 standard in that they have specific requirements for GOs. In particular, the NPCC version requires that GOs set their underfrequency tripping to meet certain criteria to ensure reliability of the BPS. Typically a dispersed generation resource site may have underfrequency protection on both the aggregating equipment (i.e., collection buses or feeders) as well as the individual generating units. Were this standard only to apply to aggregating equipment, the net impact to the BPS should a system disturbance occur may still result in a loss of significant generating capacity should each of the individual generating units trip for the event. Therefore it may be appropriate to include the individual generating units at a dispersed generation resource site as subject to this standard. The standard could be interpreted this way as written, but further clarification in the standard language may be considered. While this standard may need to be modified to clarify the applicability for dispersed generation resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification..*

The SERC version of PRC-006 requires GOs to provide, upon request, certain under and overfrequency related setpoints and other related capabilities of the site relative to system disturbances. It may be appropriate to include the capabilities of the individual generating units at a dispersed generation resource site when providing this information; however, it may be sufficient to provide only the capabilities of a single sample unit within a site as these units are typically set identically. This would be in addition to any related capabilities or limitations of the aggregating equipment as well. This may be accomplished by providing clarifications in the requirements sections. While this standard may need to be modified to clarify the applicability for dispersed power producing resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification..*

4.10.9 PRC-015 — Special Protection System Data and Documentation
PRC-016 — Special Protection System Misoperations
PRC-017 — Special Protection System Maintenance and Testing

Relatively few dispersed power producing resources own or operate Special Protection Systems (SPSs); however, they do exist and therefore need to be evaluated for applicability based on the revised BES definition. The vast majority of these SPSs involve the aggregating equipment (transformers, collection breakers, etc.) and not the individual generating units. The SPSs are installed to protect the reliability of the BPS, and as such the aggregated response of the site (e.g., reduction in output, complete disconnection from the BES, etc.) is critical, not the response of individual generating units. *Therefore, the applicability of these standards does not need to be changed for dispersed power producing resources.*

4.10.10 PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Dispersed power producing resources typically utilize a site level voltage control scheme that directs the individual generating units to adjust their output to meet the voltage requirements at an aggregate Facility level. In these cases the individual generating units will simply no longer respond once they are "maxed out" in providing voltage or reactive changes, but also need to be properly coordinated with protection trip settings on the aggregating equipment to mitigate risk of tripping in this scenario. For those facilities that solely regulate voltage at the individual unit, these facilities also need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. The applicability in PRC-019-1 (section 4.2.3) includes a "Generating plant/Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating)." *Therefore, the DGR SDT revised the Facilities section of the standard to clarify that facilities which solely regulate voltage at the individual generating unit are subject to this standard's requirements. The SDT's recommended applicability changes to PRC-019-1 were posted for an initial comment and ballot period scheduled to close December 22, 2014.*

4.10.11 PRC-023— Transmission Relay Loadability

Dispersed power producing resources in some cases contain facilities and Protection Systems that meet the criteria described in the Applicability Section (e.g., load responsive phase Protection System on transmission lines operated at 200 kV or above); however, in the majority of cases these lines are radially connected to the remainder of the BES and are excluded from the standard requirements of PRC-023-3. While certain entities with dispersed power producing resources are required to meet the requirements of PRC-023 on components of their aggregating equipment (e.g., main step-up transformers, interconnecting transmission lines) the standard is not applicable to the individual generating units, as the individual generating units are addressed in PRC-025. The BES definition changes have no direct impact on the applicability of this standard to dispersed power producing resources. *Therefore, the applicability of this standard does not need to be changed for dispersed power producing resources.*

4.10.12 PRC-024— Generator Frequency and Voltage Protective Relay Settings

If the individual generating units at a dispersed power producing resource were excluded from this requirement, it is possible large portions or perhaps the entire output of a dispersed power producing resource site may be lost during certain system disturbances, negatively impacting BES reliability. The SDT has determined it is appropriate to require that Protection System settings applied on both the individual generating units and aggregating equipment (including any Protection Systems applied on non-BES portions of the aggregating equipment), are set within the "no-trip zone" referenced in the requirements to maintain reliability of the BES. However, for the purpose of compliance evidence, the SDT believes it should be sufficient for an entity to provide evidence for a single sample generating unit within a site rather than providing documentation for each individual unit, providing the entity used that methodology to set its protection systems for all the units, rather than providing documentation for each individual unit. This would be in addition to any Protection System settings evidence for the aggregating equipment. *The SDT therefore recommended changes to the standard requirements to ensure these requirements are applied to the individual power producing resources as well as all equipment, potentially including non-BES equipment, from the individual power producing resource up to the point of interconnection and communicated compliance evidence requirement considerations to NERC staff for RSAW development. The SDT's recommended applicability changes to PRC-024 were posted for an initial comment and ballot period scheduled to close December 22, 2014.*

4.10.13 PRC-025— Generator Relay Loadability

The Protection System utilized on individual generating units at a dispersed power producing Facility may include load-responsive protective relays and thus would be subject to the settings requirements listed in this standard. Were this standard only to apply to aggregating equipment, the net impact to the BPS should a system disturbance occur, may be a loss of significant generating capacity should each of the individual generating units trip for the event. The SDT has determined it is appropriate to require that Protection System settings applied on both the individual generating units at a dispersed power producing resource site as applicable to this standard. However, for the purpose of compliance evidence, the SDT believes it should be sufficient for an entity to provide evidence for a single sample generating unit within a site rather than providing documentation for each individual unit, providing the entity used that methodology to set its protection systems for all the units, rather than providing documentation for each individual unit. This would be in addition to any Protection System settings evidence for the aggregating equipment. As such the SDT recommends the RSAW be modified as stated above. *The SDT recommended no changes to the standard; however, the DGR SDT communicated compliance evidence requirement considerations to NERC staff for RSAW development.*

4.11 TOP

The TOP standards provide TOPs their authority. There are four TOP standards that apply directly to GO and GOP entities. The TOP standards as they relate to GOs/GOPs ensure RCs and TOPs can issue directives to the GOP, and the GOP follows such directives. They also ensure GOPs render all available emergency assistance as requested. Finally, they require GO/GOPs to coordinate their operations and outages and provide data and information to the BA and TOP. No TOP standard refers to the interaction of a host BA, TOP, or RC with individual BES Elements.

4.11.1 TOP-001-1a — Reliability Responsibilities and Authorities

This standard as it applies to GOPs is reviewed at the requirement level, with only one change recommended.

4.11.1.1 Requirement R3

The purpose of requirement R3 as it relates to GOPs is to ensure the RC and TOP reliability directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow a RC or TOP reliability directive they are to inform the RC or TOP immediately of such. The requirement is applicable to the registered functional entity, not the constituent Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed power producing resources from any other GOP resources, and no change to this requirement is needed.*

4.11.1.2 Requirement R6

The purpose of requirement R6 as it relates to GOPs is to ensure all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements. The requirement is applicable to the registered functional entity, not the constituent Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed power producing resources from any other GOP resources, and no change to this requirement is needed.*

4.11.1.3 Requirement R7

The purpose of requirement R7 as it relates to GOPs is to ensure BES facilities are not removed from service without proper notification and coordination with the TOP and, when time does not permit such prior notification and coordination, notification and coordination shall occur as soon as reasonably possible. This is required to avoid burdens on neighboring systems. It should be noted that the purpose of this standard is to keep the TOP informed of all generating Facility capabilities in case of an emergency. It is assumed that required notification and coordination from the GOP to the TOP would be done in real-time and through verbal communication media. The concern here is how to apply this to a dispersed power producing resource Facility. The SDT recommends that the GOP report at the aggregate Facility level to the TOP any generator outage above 20 MVA for dispersed power producing resource facilities. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition, which addresses only generating units greater than 20 MVA.
- TOP-002-2.1b Requirement R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the Facility (e.g., 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.

Dispersed power producing resource outages should be reported as X MW out of Y MW are available. *Therefore, the SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for generator outages greater than 20 MVA.*

4.11.2 TOP-001-3— Transmission Operations[21]

The purpose of this standard as it relates to GOPs is to ensure TOP directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow a TOP directive they are to inform the TOP immediately of such. It directs the TOP to issue directives and as such the TOP may provide special requirements for dispersed power producing resources for its unique capabilities. *The SDT recommends that Project 2014-3 provide direction for a dispersed power producing resource to be only reported at the aggregate facility level. If TOP-001-1a R7 is reintroduced, then the recommendation provided above should be included in their efforts.*

4.11.3 TOP-002-2.1b — Normal Operations Planning[22]

This TOP standard has five requirements applied to GOPs. Several modifications are recommended below, and the SDT recommends that the most effective and efficient way to accomplish this is through modification of the Applicability Section of this standard.

4.11.3.1 Requirement R3

The purpose of requirement R3 as it relates to GOPs is to ensure a GOP's current day, next-day and seasonal operations are coordinated with its host BAs and TSP. This requirement relates to planned operations at a generator and does not include unplanned operations such as forced or emergency operations. The SDT recommends that this requirement be applied at the aggregate Facility level for dispersed power producing resources. For example, forecasting available MW at the aggregated Facility level is currently one method used. The SDT does not see any reliability gap that would prompt this team to apply R3 to any point less than the dispersed power resource aggregated Facility level.
The SDT has not found or been made aware of a reliability gap that would prompt this team to apply R3 to any point less than the dispersed power resource aggregated Facility level and recommends such modification to the applicability of this requirement.

4.11.3.2 Requirement R13

The purpose of requirement R13 as it relates to GOPs is to ensure Real Power and Reactive Power capabilities are verified as requested by the BA and TOP. The SDT believes a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT is recommending that this requirement be applied at the aggregate Facility level for dispersed power producing resources for the following reasons:

- Due to the nature, amount of individual generators at a dispersed power producing resource, internal Real Power losses, and natural inductance and capacitance of dispersed power resource system connected in series, verification of real and reactive capabilities should be conducted at the dispersed power producing resource aggregate Facility level. Performing verification in this manner will provide an actual net real and reactive capability, which would be seen by both the BA and TOP. In addition, performing verification in this manner is also consistent with operating

[21] Note that TOP-001-2 was adopted by the Board and remanded by FERC. TOP-001-2 is currently under revision as part of Project 2014-03 – Revisions to TOP and IRO Standards, and was posted for additional ballot period that is scheduled to close January 7, 2015 as TOP-001-3.
[22] The GOP applicability is removed in TOP-002-3, which was adopted by the Board. However, TOP-002-3 was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

agreements such as an interconnection agreement, which the dispersed power resource has with the TOP and BA.
- MOD-025-2 also provides that verification for any generator <20MVA may be completed on an individual unit basis or as a "group." Reporting capability at the aggregated Facility level is consistent with the MOD-025-2 provision for group verification.

The SDT recommends a modification to the applicability of this requirement at the aggregated Facility level for dispersed power producing resources.

4.11.3.3 Requirement R14

The purpose of requirement R14 as it relates to GOPs is to ensure BAs and TOPs are notified of changes in real output capabilities without any intentional time delay. It should be noted that the purpose of this requirement is to address unplanned changes in real output capabilities. It is assumed the required notification and coordination from the GOP to the BA and TOP would be done in real-time and through verbal communication media. The concern here is how to apply this to dispersed power producing resources. The SDT recommends that the GOP notify at the aggregate Facility level to the TOP any unplanned changes in real output capabilities above 20 MVA. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition which includes generating units greater than 20MVA.
- TOP-002-2.1b R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the Facility (e.g. 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.

Dispersed generation resources changes in real output capabilities should be reported as X MW out of Y MW are available. *The SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for unplanned outages greater than 20 MVA.*

4.11.3.4 Requirement R15

The purpose of requirement R15 as it relates to GOPs is to ensure BAs and TOPs are provided a forecast (e.g., seven day) of expected Real Power. The SDT believes this requirement as requested by the BA or TOP is being applied at the aggregate Facility level for dispersed power producing resources.

Based on the SDT's experience, expected Real Power forecasts (e.g. 5 or 7 forecast) for a dispersed power producing resource has been traditionally coordinated with the BA and TOP at the aggregate Facility level for dispersed power producing resources. *Therefore, the SDT recommends that R15 be applied at the aggregate Facility level for dispersed power resources and as such, modification to the applicability of this requirement is necessary.*

4.11.3.5 Requirement R18

The purpose of requirement R18 as it relates to a GOP is to ensure uniform line identifiers are used when referring to transmission facilities of an interconnected network. The standard applies to transmission facilities of an interconnected network, which would not apply to any Elements within the dispersed generation Facility. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

4.11.4 TOP-003-1— Planned Outage Coordination

This TOP Standard has three requirements applied to GOPs. Modification to one of these requirements is recommended.

4.11.4.1 Requirement R1

The purpose of requirement R1 as it relates to GOPs is to ensure TOPs are provided planned outage information on a daily basis for any scheduled generator outage >50MW for the next day. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

4.11.4.2 Requirement R2

The purpose of requirement R2 as it relates to GOPs is to ensure all voltage regulating equipment scheduled outages are planned and coordinated with affected BAs and TOPs. A modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT recommends that this requirement be applied at the aggregate Facility level for dispersed power producing resources.

Based on the SDT's experience, scheduled outages of voltage regulating equipment at a dispersed power producing resource has been traditionally provided to the BA and TOP at the aggregate Facility level for dispersed power producing resources. Outages of voltage regulating equipment at a dispersed power producing resource are coordinated typically as a reduction in Reactive Power capabilities, specifying whether it is inductive, capacitive or both. Additionally, automatic voltage regulators that do not necessarily provide Reactive Power, but direct the actions of equipment that do supply Reactive Power, are typically coordinated at the aggregate Facility level as they usually are the master controller for all voltage regulating equipment at the Facility. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap, which would prompt this team to apply R2 to any point less than the dispersed power producing resource aggregated Facility level and as such, determined a modification to the applicability of this requirement is necessary for dispersed power producing resources.*

4.11.4.3 Requirement R3

The purpose of requirement R3 as it relates to GOPs is to ensure scheduled outages of telemetering and control equipment and associated communication channels are planned and coordinated among BAs and TOPs. Based on the SDT technical expertise, scheduled outages of telemetering and control equipment and associated communication channels at a dispersed power producing resource have been traditionally provided to the BA and TOP at the aggregate Facility level for dispersed power producing resources. In addition, only scheduled outages of telemetering and control equipment and associated communication channels that can affect the BA and TOP are coordinated with the BA and TOP. *Therefore, the applicability of this requirement does not need to be changed for dispersed power producing resources.*

4.11.5 TOP-006 — Monitoring System Conditions

The purpose of this standard as it relates to GOPs is to ensure BAs and TOPs know the status of all generation resources available for use as informed by the GOP. It should also be noted that the purpose of this standard is to ensure critical reliability parameters are monitored in real-time. It then can be extrapolated that the requirement, "GOP shall inform…," is done by sending dispersed power producing resource telemetry in real-time and through a digital communication medium, such as an ICCP link or RTU. The SDT feels a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT is recommending that this requirement be applied at the aggregate Facility level for dispersed power producing resources for the following reasons:

- This is consistent with Inclusion I2 of the revised BES definition, which includes generating units greater than 20MVA. If removing <20MVA would cause a burden to the BPS, then the threshold for inclusion in the BES would have been less than 20MVA.
- Routine maintenance is frequently completed on a small portion of the entire Facility (e.g. 2% of the generators are out of service on any given day) such as to not have a significant impact to the output capability of the Facility. Additionally, it is not uncommon to have individual generating units at a dispersed power producing resource to go into a failure mode due to internal factors of the equipment, such as hydraulic fluid pressure tolerances, gearbox bearing thermal tolerances, etc. As such, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.
- As this standard requires real-time monitoring, this is most likely completed through a digital medium such as an ICCP link or RTU. The data that a dispersed power resource provides to the BA and TOP in real-time should include the aggregate active power output of the Facility, among other telemetry points. These data specifications are usually outlined in interconnection agreements among the parties.

Based on the SDT technical expertise, BAs and TOPs are informed by the GOP of all generation resources available at the dispersed power producing resource at the aggregate Facility level. Traditionally the dispersed power producing resources are providing the BA and TOP, at minimum, the following telemetry points in real-time: aggregate Real Power, aggregate Reactive Power and main high-side circuit breaker status. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap, which would prompt this team to apply this requirement to any point less than where the dispersed power producing resource aggregates and as in such, recommends a modification to the applicability of this requirement is necessary for dispersed power producing resources.*

4.12 TPL

At the time of this paper, these standards do not affect GOs or GOPs directly. Input from GO or GOP entities is provided to transmission planning entities through the MOD standards. *Therefore, the applicability of the TPL standards does not need to be changed for dispersed power producing resources.*

4.13 VAR

The VAR standards exist to ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained. There are two VAR Standards that apply to GOs and/or GOPs.

The voltage and/or reactive schedule provided by TOPs is specified to be at the point of interconnection or the point specified in the interconnection agreement.

4.13.1 VAR-001 — Voltage and Reactive Control (WECC Regional Variance)

The purpose of this standard as it relates to GOPs in WECC is to ensure a generator voltage schedule is issued that is appropriate for the type of generator(s) at a specific Facility. Additionally, it requires GOPs to have a methodology for how the voltage schedule is met taking into account the type of equipment used to maintain the voltage schedule. Based on the SDT technical expertise, voltage control and voltage schedule adherence for dispersed power producing resource occurs at the aggregate Facility level. There is no need to differentiate dispersed generation resources from any other GOP resources. *Therefore, the applicability of VAR-001 does not need to be changed for dispersed generation resources.*

4.13.2 VAR-002-2b — Generator Operation for Maintaining Network Voltage Schedules
VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

The purpose of these standards as they relate to GOs and GOPs is to ensure generators operate in automatic voltage control mode as required by the TOP voltage or reactive power schedule provided to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and reliability of the Interconnection. Based on the SDT technical expertise, voltage control and voltage schedule adherence for dispersed power producing resource occurs at the aggregate Facility level and such guidance should be provided.

In addition, the voltage-controlling equipment and the methodology to ensure the Facility has an automatic and dynamic response to ensure the TOP's instructions are maintained can be very different for each Facility. It is implied in VAR-001-3 that each TOP should understand capabilities of the generation Facility and the requirements of the transmission system to ensure a mutually agreeable solution/schedule is used.

4.13.3 VAR-002-2b — Requirement R3.1
VAR-002-3 — Requirement R4

The purpose of these requirements is to ensure that a GOP notifies the TOP, within 30 minutes, of any status and capability changes of any generator Reactive Power resource, including automatic voltage regulators, power system stabilizers or alternative voltage controlling devices. Based on the experience of the SDT, status and capability changes are traditionally coordinated at the aggregate Facility level point of interconnection. *Therefore, the SDT has recommended changes to the standard to clarify the applicability of VAR-002-2b R3.1 and VAR-002-3 R4 for dispersed power producing resources. These changes were successfully balloted in VAR-002-4 on November 6, 2014, and approved by the Board on November 13, 2014.*

4.13.4 VAR-002-2b — Requirement R4
VAR-002-3 — Requirement R5

The purpose of these requirements is to ensure that Transmission Operators and Transmission Planners have appropriate information and provide guidance to the GOP in regards to the Generator Operator's transformers to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and reliability of the Interconnection. Based on the experience of the SDT, dispersed power producing resources' individual generator transformers have traditionally been excluded from the requirements of VAR-002-2b R4 and VAR-002-3 R5, as they are not used to improve voltage performance on the Interconnection. As such, applicability should be limited to transformers with at least one winding at a voltage of 100kV or above. *Therefore, the SDT has recommended changes to the standard to clarify the applicability of VAR-002-2b R4 and VAR-002-3 R5 for dispersed generation resources. These changes were successfully balloted in VAR-002-4 on November 6, 2014, and approved by the Board on November 13, 2014.*

4.14 CIP

4.14.1 CIP v5

The CIP standards are still under revision in Project 2014-02. The DGR SDT and the CIP SDT continue to coordinate revisions to the CIP standards, and will update this section to reflect the outcome of that effort at the appropriate time.

The CIP standards ensure physical and cyber security for BES Cyber Assets and BES Cyber Systems critical to the reliability and security of the BES. CIP-002 identifies critical assets or systems of a Facility, while CIP-003 to CIP-011 depend on the outcome of the CIP-002 assessment to determine applicability.

During the Project 2014-02 CIP Version 5 Revisions SDT first comment period, it received comments to modify CIP-003-6 in the Applicability Section. The CIP SDT made drastic modifications to the second posting of CIP-003-6 to take into account all of the comments received, which was posted for an additional 45-day comment and ballot period on September 3, 2014.

At its September meeting, the DGR SDT had a focused discussion with the CIP SDT surrounding the technical nature of the dispersed power producing resources and how it relates to the CIP standards. The coordinating effort resulted in discussions of the revised CIP-003-6. As for that posted revised standard, the CIP SDT took the approach of including an Attachment 1 for Responsible Entities. The Attachment 1 requires elements to be developed in Responsible Entities' cyber security plan(s) for assets containing low impact BES Cyber Systems. The elements in CIP-003-6, Attachment 1 allow flexibility for the controls to be established for each of the main four elements below. The CIP SDT encourages observers of the DGR SDT to review the Attachment 1 in detail. Here is some information regarding the attachment.

Element 1: Security Awareness

The intent of the security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. It is up to the entity as to the topics and how it schedules these topics. The Responsible Entity should be able to produce the awareness material that was delivered and the delivery method(s) (posters, emails, topics at staff meetings, etc.) that were used. The SDT does not intend that the Responsible Entity must maintain lists of recipients and track the reception of the awareness material by personnel.

Element 2: Physical Security

The Responsible Entity has flexibility in the controls used to restrict physical access to low impact BES Cyber Systems at a BES asset using one or a combination of access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may utilize perimeter controls (e.g., fences with locked gates, guards, site access policies, etc.) and/or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses. User authorization programs and lists of authorized users are not required.

Element 3: Electronic Access Controls

Where Low Impact External Routable Connectivity (LERC) or Dial-up Connectivity exists, the Responsible Entity must document and implement controls that include the LERC and Dial-up Connectivity to the BES asset such that the low impact BES Cyber Systems located at the BES asset are protected. Two glossary terms are included in order to help clarify and simplify the language in Attachment 1. The SDT's intent in creating these terms is to avoid confusion with the similar concepts and requirements (ESP, EAP, ERC, EACMS) needed for high and medium impact BES Cyber Systems by utilizing separate terms that apply only to assets containing low impact BES Cyber Systems.

Element 4: Cyber Security Incident Response

The entity should have one or more documented cyber security incident response plans that include each of the topics listed. For assets that do not have LERC, it is not the intent to increase their risk by increasing the level of connectivity in order to have real-time monitoring. The intent is, if in the normal course of business suspicious activities are noted at an asset containing low impact BES Cyber Systems, there is a cyber security incident response plan that will guide the entity through responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Therefore, the DGR SDT recommends that no changes be made to proposed CIP-003-6. CIP-002-5.1 needs to remain as is because entities must go through the process for identifying and categorizing its BES Cyber Systems and their associated BES Cyber Assets. The controls put in place for proposed CIP-003-6, Attachment 1, are not burdensome, are realistic and achievable, and do not express undue compliance burden. In conclusion, the DGR SDT states that the reliability objective of these controls are adequate and the applicability of CIP-003-6 should not be modified.

The SDT states that the CIP Version 5 Revisions SDT should consider developing guidance documentation around the following areas:

- Low Impact BES Cyber Systems that must comply with a limited number of requirements, all located in CIP-003-5. The only technical requirement is R2, which will be modified during the current drafting activity to add clarity to the requirement. The SDT notes that the CIP Version 5 Revisions SDT should consider developing guidance around how this requirement relates to dispersed generation.
- Any programmable logic device that has the capability to shut down the plant within 15 minutes; and
- Remote access from third party entities into the SCADA systems that control the aggregate capacity of a Facility should be assessed to determine if there is a need of any additional cyber security policies.

The SDT intends to recommend guidance for those companies that only operate their turbines from one central location. Individual Elements lumped into a BES Cyber System should be addressed. When operations are on a turbine-by-turbine basis, the SDT believes there should not be rigid controls in place. The inability to "swim upstream" should be addressed as well. Further, the guidance intends to address when manufacturers operate or have control of the SCADA environment to conduct troubleshooting and other tasks, and ensure that proper security is in place.

NERC staff has committed to facilitate communication between the SDT and the CIP Version 5 Revisions SDT as appropriate to ensure alignment and to develop language for guidance, coordinated between the two SDTs. *Therefore, the applicability of CIP standards does not need to be changed for dispersed generation resources.*

Appendix A: List of Standards

Appendix B: List of Standards Recommended for Further Review

Exhibit D

Order No. 672 Criteria

OMITTED

Exhibit E

Summary of Development History and Complete Record of Development of Proposed Reliability Standards

Exhibit E: Summary of Development History

The development record for the proposed Reliability Standards is summarized below.

I. Overview of the Standard Drafting Team

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

II. Standard Development History

A. Standard Authorization Request ("SAR") Development

A SAR for Project 2014-01 Standards Applicability for Dispersed Generation Resources ("DGR") was posted for a 30-day formal comment period from November 20, 2013 through December 19, 2013. The NERC Standards Committee approved the revised SAR on October 17, 2013.

B. First Posting for White Paper-Informal Comment Period

A draft White Paper was posted for an informal comment period from April 17, 2014 through May 5, 2014. There were 24 sets of comments, including comments from approximately 82 different individuals and approximately 54 companies, representing 9 of the 10 industry segments. After consideration of each comment the standard drafting team revised or its recommendations where suggested changes were consistent with the standard drafting team's intent and industry consensus.

C. First Posting - Formal Comment Period, Initial Ballots

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

Five proposed Reliability Standards, PRC-005-2(X), PRC-005-3(X), PRC-005-X(X), VAR-002-2(b)(X), and VAR-002-4, were posted for a 45-day public comment period from June 12, 2014 through July 28, 2014, with an initial ballot held from July 18, 2014 through July 29, 2014. The initial ballot for PRC-005-2(X) achieved 79.49% quorum, and an approval of 91.38%, PRC-005-3(X) achieved 80.15% quorum, and an approval of 92.20%, PRC-005-X(X) achieved 80.00% quorum, and an approval of 89.51%, VAR-002-2(b)(X) achieved 80.83% quorum, and an approval of 90.58%, and VAR-002-4 achieved 80.36% quorum, and an approval of 87.09%. There were 38 sets of comments, including comments from approximately 127 different individuals and approximately 75 companies, representing 9 of the 10 industry segments.

The standard drafting team considered stakeholder comments regarding the proposed Reliability Standards and made modifications based on those comments. A summary of the responses to comments and changes made is included in the Consideration of Comments for the posting.

D. First Posting - Formal Comment Period, Initial Ballots

Proposed Reliability Standards PRC-004-2.1a(X) and PRC-004-3(X) were posted for a 45-day public comment period from July 10, 2014 through August 26, 2014, with an initial ballot held from August 15, 2014 through August 26, 2014. The initial ballot for PRC-004-2.1a(X) achieved 81.79% quorum, and an approval of 92.09% and PRC-004-3(X) achieved 81.75% quorum, and an approval of 87.45%. There were 29 sets of comments, including comments from approximately 106 different individuals and approximately 77 companies, representing 9 of the 10 industry segments.

The standard drafting team considered stakeholder comments and made the following observations and non-substantive modifications based on those comments. A summary of the responses to comments and changes made is included in the Consideration of Comments for the posting.

E. Second Posting - Comment Period and Additional Ballot

Proposed Reliability Standards VAR-002-4 and VAR-002-2b(X) were posted for a 45-day public comment period from August27, 2014 through October 16, 2014, with an additional ballot held from October 7, 2014 through October 16, 2014. The additional ballot for VAR-002-4 achieved an 81.91% quorum, and an approval of 94.92% and VAR-002-2b(X) achieved an 82.12% quorum, and an approval of 94.37%. There were 18 sets of comments, including comments from approximately 88 different individuals and approximately 63 companies, representing 9 of the 10 industry segments. After consideration of each comment the standard drafting team concluded that no further changes, beyond correction of typographical errors were necessary to the documents. VAR-002-2b was replaced by a successor Reliability Standard, VAR-002-3, and was retired. Therefore, VAR-002-2b(X) was removed from the project.

F. Final Ballots

Proposed Reliability Standards PRC-005-2(X) and PRC-005-3(X) were posted for a 10-day final ballot period from October 27, 2014 through November 5, 2014. PRC-005-2(X) achieved 85.32% quorum, and an approval of 95.35% and PRC-005-3(X) achieved 86.01% quorum, and an approval of 95.86%.

G. Second Posting- Comment Period and Additional Ballots

Proposed Reliability Standards PRC-004-2.1a(X) and PRC-004-4 were posted for a 45-day public comment period from September 5, 2014 through October 22, 2014, with an additional ballot held from October 10, 2014 through October 22, 2014. The additional ballot for PRC-004-2.1a(X) achieved 85.13% quorum, and an approval of 94.75% and PRC-004-4 achieved 83.29% quorum, and an approval of 93.98%. There were 24 sets of comments, including comments from approximately 77 different individuals and approximately 55 companies, representing all 10 industry segments.

The standard drafting team considered stakeholder comments regarding proposed Reliability Standard PRC-004 and made only minor non-substantive changes.

H. Final Ballots

Proposed Reliability Standards PRC-004-2.1(i)a, PRC-004-4, and VAR-002-4 were posted for a 10-day final ballot period from October 28, 2014 through November 6, 2014. PRC-004-2.1(i)a achieved quorum of 89.49% and an approval of 92.91%. PRC-004-4 achieved quorum of 87.66% and an approval of 92.15%. VAR-002-4 achieved quorum of 87.08% and an approval of 95.62%.

I. Second Posting for White Paper - Comment Period

A draft White Paper was posted for a comment period from December 22, 2014 through January 20, 2015. At the time of filing, the standard drafting team was considering the comments submitted.

J. Board of Trustees Adoption

Proposed Reliability Standards PRC-004-2.1(i)a, PRC-004-4, VAR-002-4, PRC-005-2(i), and PRC-005-3(i) were adopted by the NERC Board of Trustees on November 13, 2014.

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Related Files

Status:
A 45-day formal comment period and 30-day initial ballot for proposed applicability changes as reflected in **PRC-005-5- Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** concluded at **8 p.m. Eastern on Thursday, January 22, 2015**. The ballot results can be accessed via the links below. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Final ballots for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team concluded **8 p.m. Eastern, Thursday, January 22, 2015.** The ballot results can be accessed via the links below. The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Those standards are as follows:
PRC-001-1.1(ii) - System Protection Coordination
PRC-019-2 - Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
PRC-024-2 - Generator Frequency and Voltage Protective Relay Settings

Board Adopted: November 13, 2014 - PRC-004-2.1(i)a, PRC-004-4, PRC-005-2(i), and PRC-005-3(i)

Filed with FERC:

Order Effective:

Enforcement Date:

Background:
The Standards Authorization Request (SAR) asks that the applicability section of certain Reliability Standards that apply to a Generator Owner (GO)/Generator Operator (GOP) or the requirements of certain GO/GOP Reliability Standards be reviewed, and where appropriate revised to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Electric System (BES). Dispersed generation resources are those resources that are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.
This request is related to the revised definition of the Bulk Electric System (BES) from Project 2010-17, and it is desirable to complete any revisions determined to be necessary so that revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the revised BES definition. This effective date is expected to be July 1 2016, although it is possible that regulatory action could change the date.

Draft	Actions	Dates	Results	Consideration of Comments
Final Drafts **PRC-001-1.1(ii)** Clean | Redline to Last Posted | Redline to PRC-001-1.1 **PRC-019-2** Clean | Redline to Last Posted | Redline to PRC-019-1 **PRC-024-2** Clean | Redline to Last Posted | Redline to PRC-024-1 **Implementation Plans** **PRC-001-1.1(ii)** Clean | Redline to Last Posted **PRC-019-2** Clean | Redline to Last Posted **PRC-024-2** Clean | Redline to Last Posted SAR	Final Ballots Info>> Vote>> (Closed)	01/13/15 - 01/22/15	Summary>> Ballot Results PRC-001-1.1(ii)>> PRC-019-2>> PRC-024-2>>	

White Paper Clean **(132)** | Redline to Last Posted **(133)** **Appendix A** – List of all NERC standards applicable to GOs/GOPs **(134)** **Appendix B** – NERC standards recommended for consideration to clarify applicability for dispersed generation **(135)** Unofficial Comment Form(Word) **(136)**	Comment Period Info>> **(137)** Submit Comments>> (Closed)	12/22/14 - 01/20/15	Comments Received>> **(138)**	
Draft 1 PRC-005-5 Clean | Redline to Last Posted Implementation Plan **Supporting Documents** Unofficial Comment Form (Word) SAR	Initial Ballot Info>> Vote>> (Closed)	1/12/15 – 1/22/15	Summary>> Ballot Results>>	
	Comment Period Info>> Submit Comments>> (Closed)	12/8/14 – 1/22/15	Comments Received>>	
	Join Ballot Pool Info>> Join>> (Closed)	12/8/14 – 1/8/15		

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Clean | Redline to PRC-001-1.1

PRC-019-2
Clean | Redline to PRC-019-1

PRC-024-1(X)
Clean | Redline to last posted PRC-024-1

Implementation Plans
PRC-001-1.1(X)

PRC-019-2

PRC-024-1(X)

Supporting Documents
Unofficial Comment Form (Word)

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PRC-019-2

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Redline to last posted
(115)

Redline to PRC-004-2.1a (116)

PRC-004-4
Clean (117) |
Redline to last posted
(118)

Redline to PRC-004-3 (119)

VAR-002-4
Clean (120) |
Redline to last posted
(121)

Redline to VAR-002-3 (122)

Implementation Plans

PRC-004-2.1(i)a
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(No changes to last posted)

PRC-004-4
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(No changes to last posted)

VAR-002-4
Clean (125)
(No changes to last posted)

SAR (126)</td>
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Vote>>

(Closed)</td>
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Ballot Results

PRC-004-2.1(i)a>>
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PRC-004-4>>
(130)

VAR-002-4>> (131)</td>
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Redline to PRC-005-3 **(83)** **Implementation Plans** PRC-005-2(X) **(84)** PRC-005-3(X) **(85)** **Supporting Documents** Coordination Plan and Explanation of Version Numbers **(86)** SAR **(87)**				
Draft 2 **VAR-002-2b(X)** Clean **(60)** Redline to Last Posted **(61)** Redline to VAR-002-2b **(62)** **VAR-002-4** Clean **(63)** Redline to last posted **(64)** Redline to VAR-002-3 **(65)** **Implementation Plan** VAR-002-2b(X) **(66)** VAR-002-4 **(67)** **Supporting Documents**	Additional Ballots Updated Info>> **(71)** Info>> **(72)** Vote>> (Closed)	10/7/14 – 10/16/14	Summary>> **(74)** Ballot Results VAR-002-4>> **(75)** VAR-002-2b(X)>> **(76)**	
	Comment Period Info>> **(73)** Submit Comments>> (Closed)	8/27/14 – 10/16/14	Comments Received>> **(77)**	

Unofficial Comment Form (Word) **(68)** Coordination Plan and Explanation of Version Numbers **(69)** SAR **(70)**				
Draft 1 Standard **PRC-004-2.1a(X)** Clean **(43)** | Redline to PRC-004-2.1a **(44)** **PRC-004-3(X)** Clean **(45)** | Redline to PRC-004-3 **(46)** **Implementation Plans**	Initial Ballots Updated Info>> **(52)** Info>> **(53)** Vote>> (Closed)	8/15/14 – 8/26/14	Summary>> **(55)** Ballot Results PRC-004-2.1a(X)>> **(56)** PRC-004-3(X)>> **(57)**	
PRC-004-2.1a(X) **(47)** PRC-004-3(X) **(48)** **Supporting Documents**	Comment Period Info>> **(54)** Submit Comments>> (Closed)	7/10/14 – 8/26/14	Comments Received>> **(58)**	Consideration of Comments>> **(59)**
Unofficial Comment Form (Word) **(49)** Coordination Plan and Explanation of Version Numbers **(50)** SAR **(51)** **Draft Reliability Standard Audit Worksheets (RSAW)** PRC-004-2.1a	Join Ballot Pools>> (Closed) Please note: As a convenience to stakeholders, if you have previously joined the ballot pool for VAR-002-2b(X), no action is needed - you have automatically been entered into both the PRC-004-2.1a(X) and PRC-004-3(X) ballot pools. If you have been automatically entered and do not wish to participate, please contact Wendy	7/10/14 - 7/16/14		

PRC-004-3 PRC-005-1.1b	Muller **prior to July 16, 2014** to have your name removed.			
Draft 1 Standards **PRC-005-2(X)** Clean **(13)** | Redline to PRC-005-2 **(14)** **PRC-005-3(X)** Clean **(15)** | Redline to PRC-005-3 **(16)** **PRC-005-X(X)** Clean **(17)** | Redline to last posted PRC-005-X **(18)** **VAR-002-2b(X)** Clean **(19)** | Redline to VAR-002-2b **(20)** **VAR-002-4** Clean **(21)** | Redline to VAR-002-3 **(22)**	Initial Ballots Updated Info>> **(31)** Info>> **(32)** Vote>> (Closed)	7/18/14 – 7/29/14	Summary>> **(35)** Ballot Results: PRC-005-2(X)>> **(36)** PRC-005-3(X)>> **(37)** PRC-005-X(X)>> **(38)** VAR-002-2b(X)>> **(39)** VAR-002-4>> **(40)**	
Implementation Plans PRC-005-2(X) **(23)** PRC-005-3(X) **(24)** PRC-005-X(X) **(25)** VAR-002-2b(X) **(26)** VAR-002-4 **(27)**	Formal Comment Period Info>> **(33)** Submit Comments>> (Closed)	6/12/14 – 7/29/14	Comments Received>> **(41)**	Consideration of Comments>> **(42)**
Supporting Documents Unofficial Comment Form (Word) **(28)** Coordination Plan and Explanation of Version Numbers **(29)**	Join Ballot Pool Info>> **(34)** Join>> (Closed) Please note: these ballot pool join periods have been extended to 8 p.m. Eastern on Wednesday, July 16, 2014 in order to keep	6/12/14 – 7/16/14		

SAR **(30)** **Draft Reliability Standard Audit Worksheets (RSAW)** VAR-002-2b VAR-002-3	the closing dates for Project 2014-01 the same.			
White Paper **(6)** **Appendix A** – List of all NERC standards applicable to GOs/GOPs **(7)** **Appendix B** – NERC standards recommended for consideration to clarify applicability for dispersed generation **(8)** Unofficial Comment Form **(9)**	Informal Comment Period Info>> **(10)** Submit Comments>>	04/17/14 - 05/05/14	Comments Received>> **(11)**	Consideration of Comments>> **(12)**
SAR **(1)** **Supporting Documents:**	Comment Period Info>> **(3)**	11/20/13 - 12/19/13 (closed)	Comments Received>> **(4)**	Consideration of Comments>> **(5)**

Unofficial Comment Form (Word) **(2)**	Submit Comments>>			

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard	
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation
Date Submitted:	10/1/2013

SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact

SAR Type (Check as many as applicable)	
☐ New Standard	☐ Withdrawal of existing Standard
☒ Revision to existing Standard	☐ Urgent Action

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
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. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard.

PRC-005-2

Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply.

FAC-008-3

For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information
Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels. **PRC-023-3/PRC-025-1** In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements. **PRC-004-2** There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above. **VAR-002-2** Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard. **General review of IROs, MODs, PRCs, TOPs** IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

Reliability Functions		
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Unofficial Comment Form

Standard Authorization Request - Application of Certain GO/GOP Reliability Standards and Requirements to Dispersed Generation

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the definition. The electronic comment form must be completed by **December 19, 2013**.

All documents and information about this project are available on the project page. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information

The Standards Authorization Request (SAR) asks that the applicability section of certain Reliability Standards that apply to a Generator Owner (GO)/Generator Operator (GOP) or the requirements of certain GO/GOP Reliability Standards be reviewed, and where appropriate revised to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Electric System (BES). Dispersed generation resources are those resources that are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.

This request is related to the revised definition of the Bulk Electric System (BES) from Project 2010-17, and it is desirable to complete any revisions determined to be necessary so that revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the revised BES definition. This effective date is expected to be July 1 2016, although it is possible that regulatory action could change the date.

The scope of the SAR involves review of and possible revisions to the applicability section of the following Reliability Standard applicability sections and/or Reliability Standard requirements applicable to GOs/GOPs: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, any IRO, MOD, PRC, or TOP standards that require outage and protection and control coordination, planning, next day study or real time data, or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter, or unit level for dispersed generation.

The scope of work would also include development of a technical guidance paper for Standard Drafting Teams developing new or revised standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES.

To the extent there are existing Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.

   Yes:

   No:

   Comments:

2. Do you agree that the scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources, or should the scope encompass consideration of changes to standards applicability for all small generation regardless of type? Please provide a technical rationale for your response.

   Yes:

   No:

   Comments:

3. Do you agree with the list of standards to be reviewed? If you do not agree, please note specific standards you think should be added to or removed from the list.

   Yes:

   No:

   Comments:

4. Are you aware of any business practice that will be needed or that will need to be modified as a result of this SAR should it move forward? If yes, please identify the business practice.

   Yes:

   No:

   Comments:

5. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.

   Yes:

   No:

   Comments:

6. Are there any other concerns with this SAR that haven't been covered in previous questions?

   Yes:

   No:

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources

SAR Formal Comment Period: November 20, 2013 – December 19, 2013

Now Available

A 30-day formal comment period for the Project 2014-01 Standards Applicability for Dispersed Generation Resources Standard Authorization Request (SAR) is now open through **8 p.m. Eastern on Thursday, December 19, 2013.**

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Thursday, December 19, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (28 Responses)
Name (17 Responses)
Organization (17 Responses)
Group Name (11 Responses)
Lead Contact (11 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (1 Responses)
Comments (28 Responses)
Question 1 (27 Responses)
Question 1 Comments (27 Responses)
Question 2 (24 Responses)
Question 2 Comments (27 Responses)
Question 3 (0 Responses)
Question 3 Comments (27 Responses)
Question 4 (0 Responses)
Question 4 Comments (27 Responses)
Question 5 (0 Responses)
Question 5 Comments (27 Responses)
Question 6 (0 Responses)
Question 6 Comments (27 Responses)

Group
Caithness Shepherds Flat, LLC
Jeffrey Delgado
Yes
Yes
Caithness Shepherds Flat Wind Farm (CSF), located in Oregon, supports the SAR as written and believes the scope should address dispersed generation resources with collector systems only. In the development of CSF's NERC compliance program, it became apparent that some GO/GOP applicable Reliability Standards were written with fossil fuel facilities in mind, and not generation resources such as wind. The VAR-002 standard for example, requiring reactive and voltage control of individual generators and notification of the TOP when there is a change in status, would appear to be irrelevant to the TOP, but rather the aggregate MW output at the point of interconnection should be what is relevant. CSF's wind farm consists of several hundred wind turbines, all < 3 MW in nameplate capacity. The TOP does not need to be notified about individual turbine voltage status, as any loss of voltage control of an individual turbine will not be detected by the TOP. The relevant factor is in the voltage at the point of interconnection which is controlled by a "Wind Farm Management System" WFMS voltage control system. Change in status of the WFMS would be of interest to the TOP, so the standard should allow for this variance.
Yes
No
No
No
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
No

Scope should expanded to include all small generators regardless of types. There is no specific reason to not include all. Generally, there is little reliability benefits to BES by applying NERC standards to small generators regardless of the type.
Yes
No
No
No
Group
SPP Standards Review Group
Robert Rhodes
Yes
No
We believe that this evaluation should be extended to all small generation regardless of type because the impact on the BES would be the same regardless of the source or prime mover of the generation.
While we may agree with the list of standards as presented in the SAR we would encourage the SAR drafting team to not limit itself to just those particular standards. For example, once a drafting team is established and work begins on the project, we don't want the project to be limited by the scope as currently defined in the SAR. We need to factor in some flexibility to go beyond this specific list to capture all those standards/requirements/definitions which may be impacted in this review.
Not at this time.
Although we are not aware of any specific federal regulatory requirements, the drafting team needs to keep in mind that there may be state regulatory requirements established for dispersed generation that may need to be considered in this project.
Regarding the July 2016 deadline, the drafting team needs to be sure that this effort is complete in time for the industry to be ready by July 2016. We need to be sure that as the deadline approaches, compliance preparations aren't made and then un-made as a result of a modification to an existing standard which is impacted by this effort. In the 1st line of the 1st paragraph of the Industry Need section under SAR Information, we suggest replacing 'application' with 'applicability'. In the 5th line of the 1st paragraph of the Brief Description section under SAR Information, replace 'real time' with 'Real-time', the NERC Glossary term. In the 1st line of the FAC-008-3 paragraph under SAR Information, hyphenate step-up. In the next to last line of the General review of IROs, MODs, PRCs, TOPs paragraph, change 'uneeded' to 'unneeded'.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes.
No.
Yes. It must be considered that the operating system in Quebec follows chapter R-6.01 An Act Respecting the Regie de L'Energie, which details: (1) an owner or operator of a facility with a capacity of 44 kV or more connected to an electric power transmission system; (2) an owner or operator of an electric power transmission system; (3) an owner or operator of a production facility with a capacity of 50 megavolt amperes (MVA) or more connected to an electric power transmission system; (4) a distributor with a peak capacity of over 25 megawatts (MW), whose facilities are connected to an electric power transmission system; and (5) a person who uses an electric power transmission system under an electric power transmission service agreement with the electric power carrier or with any other carrier in Québec.

No.
Individual
Thomas Foltz
American Electric Power
Yes
AEP would prefer that the solution for applicability of dispersed generation at the turbine or generating unit level would be by adjusting the BES definition accordingly. Creating a new SAR, allowing this topic be discussed within the framework of the BES definition itself, would seem the most direct and efficient way of debating the topic. However, if that cannot be accomplished, AEP supports the effort of this SAR as an alternative (though less desirable) means to accomplish the same goal.
No
We believe it is preferable, at least initially, for the scope to remain limited to dispersed generation resources.
Every standard that involves the GO and/or GOP should be included in the scope of the SAR. This does not imply that all standards should be modified, but the SDT and commenters should be afforded the opportunity to consider the impacts of such changes. For example, PRC-024, PRC-001, CIP-002 through CIP-011, etc. should be considered.
No.
No.
No.
Individual
Shirley Mayadewi
Manitoba Hydro
Yes
Yes
No
No
Although we do not have any concerns with this SAR, we have the following suggestions to improve clarity. (1) Industry Need - remove the words “Bulk Electric System” from the second paragraph to leave only the acronym, BES because this is the second instance of BES in the document. (2) SAR Information - capitalize ‘misoperation’ because it appears in the Glossary of Terms.
Individual
Patricia Metro
National Rural Electric Cooperative Association
No
NRECA does not believe this SAR is necessary. If entities with dispersed generation are registered as a Generator Owner (GO)/Generator Operator (GOP), it is the obligation of the registered entity to determine applicable standards and associated requirements and be able to explain how it complies accordingly. There is no need to modify the applicability of standards to specifically recognize dispersed generation as there is no recognizable reliability gap with the existing applicability of the standards included in this SAR.
No
See response to Question 1
See response to Question 1

Individual
David Jendras
Ameren
Yes
(1) The proposed SAR appears to advocate the GSU as the Element within these standards' applicability, which appears reasonable for a SAR. However, we believe that this conflicts with the BES Definition Phase 2 Reference figures. Our expectation is that the BES Definition would be included in the scope of this SAR.
Yes
Yes, we agree.
(1) Apply the Generator Site Boundary used in the BES Definition Reference (e.g. Figure I2-5) consistently for dispersed generation so that multiple GSU do not circumvent the 75MVA aggregate. (2) Develop a NERC Glossary definition for the term 'dispersed generation'.
Individual
Silvia Parada Mitchell
NextEra Energy
Agree
MidAmerican
Individual
Jonathan Meyer
Idaho Power
No
The BES definition in process has addressed the concerns raised in the SAR (in our opinion). Application of Standards applies to BES elements unless specifically excluded.
No
I see no need for a SAR.
No
N/A
N/A
Individual
Alice Ireland
Xcel Energy
Yes
We strongly support the objective of this SAR.
We believe that in addition to the approved standards mentioned in the SAR, NERC should communicate this issue directly to drafting teams working on active projects such as PRC-004-3 or PRC-027-1 to assure that they consider the applicability of their standard relative to dispersed generation and, if it is intended to include dispersed generation as in scope, to assure that correct terminology is used within their draft standard to avoid ambiguity and inconsistencies such as the SAR discusses for use of the term "main step up transformer" in FAC-008-3.

Individual
John Seelke
Public Service Enterprise Group
No
The SAR relies upon the phase 2 BES definition, as recently approved by the ballot body, but which has yet to be approved by the NERC Board or FERC. Under this definition, traditional generators at a site that exceed 75 MVA in aggregate as well as the all the equipment from terminals of each generator to the connection point with the BES are included in BES. Dispersed generators are treated differently. The individual dispersed generators are part of the BES if they are at a site where their aggregate nameplate capacity exceeds 75 MVA and they are connected to the BES; however, only equipment that delivers capacity from the point where those resources aggregate to greater than 75 MVA are included in the BES. Stated differently, traditional generators are contiguous with the BES, from the individual BES generators to their connection to the BES. Dispersed generators are not contiguous with the BES – the equipment that aggregate their output prior to it exceeding 75 MVA is excluded. These exclusions create a gap between dispersed BES generators and the BES they connect to. All generators should be treated comparably. The Eastern Interconnection Reliability Assessment Group (ERAG) manual supports our recommendation regarding inclusion equipment for dispersed generators. Wind farm modeling, as specified in the ERAG manual, (https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Documents/MMWG%20Procedure%20Manual%20V10.pdf) requires a high level of detail – see p. 30, item 6, which states: “Wind Farms - Include all 34.5 kV collector bus(es) and the main facility step-up transformer(s) from 34.5 kV to transmission voltage, as well as one 0.600 kV (or whatever the wind generator nominal voltage is) level bus off each collector bus with a lumped generator and lumped GSU representing the aggregate of the wind turbines attached to that collector bus and their GSUs.” Thus, the ERAG manual requires modeling of non-BES Elements under phase 2 BES definition – see the BES Webinar slides nos. 5-7. (http://www.nerc.com/pa/Stand/WebinarLibrary/bes_phase2_third_posting_20131010_webinar_final.pdf) Setting aside our phase 2 definition concerns, the SAR does not make a coherent technical case for any standards changes. As an example, the justification for a change in PRC-005-2 has contradicting statements: “Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level.” In the first sentence, it appears that manufacturers install protection and control equipment at the “dispersed generation turbine and panel level,” yet the next sentence states that “it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level.” Which is it? During the balloting of PRC-005-2, no comments were submitted to the drafting team regarding the changes proposed in the SAR for PRC-005-2. Yet only a year after the final ballot on PRC-005-2, the SAR proposes changes to PRC-005-2 (and other standards) because the phase 2 definition, according to the SAR, would result in BES equipment at “dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES.” We believe that dispersed generators will have less equipment, not more, under the proposed BES definition because of the excluded equipment under that definition. Finally, there has been no justification put forth that would justify different treatment of dispersed generation from traditional generation. See our remarks in questions 2 and 6 below.
No
As stated previously, “small generators” (traditional versus dispersed) are not treated comparably in the phase 2 definition – traditional BES generators must be contiguous with the BES but dispersed generators need not be. While we would welcome changes that provide for comparable treatment for small generators, regardless of type, the unequal treatment embedded in the phase 2 definition must be corrected before those changes are considered.

No comments
No comments
No comments
Section 303 of the NERC ROP addresses “Relationship between Reliability Standards and Competition.” Item 1 states: “Competition — A Reliability Standard shall not give any market participant an unfair competitive advantage.” By not treating all generators comparably, the SAR violates item 1. Based upon this and our prior comments, we recommend that the SAR be rejected by the Standards Committee.
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
No
The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011. Addtionally, these standards need to be listed: PRC-001/027 – Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 – In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many. PRC-019 – Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard. MOD 012/032 – In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many. MOD 025 & 026 and 027 – In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.
Response from Q1: The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011. Addtionally, these standards need to be listed: PRC-001/027 – Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 – In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many. PRC-019 – Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard. MOD 012/032 – In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many. MOD 025 & 026 and 027 – In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.

Group
MRO NERC Standards Review Forum
Russel Mountjoy
Yes
The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
Yes
The SAR does not specify what types of generation should be included for analysis as “dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Individual
Chris Scanlon
Exelon
Yes
The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
Yes
Yes, the SAR should focus on generation resources that are part of a facility that aggregates dispersed resources at 75 MVA or more. We believe the intent is to exclude individual units from certain requirements when those units do not meet the reporting criteria but are part of a facility that aggregates those units at the BES voltage level. We note that the question may lead to confusion. As written the use of "or" appears to be implying there is a choice between "dispersed generation" as used in the first clause of the question and some generation "types" (undefined but commonly understood to refer to fuel source) as used in the second clause. We do not believe the SAR should exclude generation based on fuel type.
The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is

recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate.
No
No
The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Individual
David Greyerbiehl
Consumers Energy Company
Yes
Yes
Yes
The SAR is required at a minimum, but a change to the BES definition is more appropriate. From the comments below submitted during the BES, the BES definition should at minimum be modified to provide consistency between generating resources (I2) and dispersed power producing resources (I4). Generating resources are required to be 20MVA in order to be considered an BES element, while dispersed power producing resources have no size consideration as long as they meet the net total MVA. Consumers Energy has completed studies with an operating wind farms and the loss of individual resources makes no impact the BES. The addition of individual resources does not make improve reliability as they have no effect on the system. The SAR intention is to modify the individual standards to define the requirements for all the additional BES elements that are being added that are not presently addressed in the standards or are against the manufacturers recommendations. While this approach can be used, and is required if the BES definition is not changed. A better method would be to include dispersed power producing resources at a point in which the total affects the BES and not as individual units. Previous Comments on BES definition: The inclusion and the clarification of the inclusion seem to contradict each other. The highlight portion above seems to indicate inclusion only from the point of aggregation of 75MVA or above. This, in most Wind Park cases would include a collector bus but probably not individual wind turbines. However I4 seems to indicate that the case of a Wind Park that has a total aggregation of 75 MVA, all associated equipment including every individual wild turbine would be included. There is inconsistency. If and when Distributed Generation gains saturation is it our intent that whole neighborhoods or industrial parks be considered BES resources? Technical justification should be needed to include resources in the BES, not the other way around. Is there a real expectation that a single collector circuit containing ten, 1.2MW wind turbines can cause cascading or uncontrollable outages of the surrounding system? It is extremely doubtful. We can support the inclusion of equipment where the aggregation of 75 MVA or more connects to the Bulk Electric System at voltages of 100kv or greater. There is a clear indication here that a single contingency can remove the total of the capacity from the system where with this definition as proposed, that is simply not the case.
No
No
Group
ISO/RTO Council Standards Review Committee
Greg Campoli
Yes
Yes

Small generators that do not meet the individual 20 MVA criteria and are not part of the aggregated 75 MVA group that meets the BES inclusion criteria are not regarded BES facilities and therefore do not need to be addressed by this SAR. The scope therefore does not need to be expanded to all small generators.
Yes
No
No
No
Individual
Gary Kruempel
MidAmerican Energy Company
These comments were developed by NextERA (contact Brian Murhpy), MidAmerican, and Exelon
Yes
The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
Yes
The SAR does not specify what types of generation should be included for analysis as “dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
No
No
The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Individual
Bill Fowler
City of Tallahassee (TAL)
Yes
Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Yes
Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.
yes
No. The City of Tallahassee is not aware of other business practices to be included.
No. The City of Tallahassee is not aware of such.

No.
Group
ACES Standards Collaborators
Ben Engelby
Yes
We find this SAR timely and necessary to avoid confusion in the application of the revised definition of the Bulk Electric System.
No
No, we do not agree that the scope of the SAR should be limited. The scope of the SAR should be to review standards applicable to GO/GOP and to limit the applicability based on the revised definition of the BES. Small generation regardless of type should be included in this review.
We agree with the list of standards to be reviewed. We would like to see flexibility in the scope of standards to be reviewed in the event that another standard is added during the standards development phase.
No.
No.
No other concerns.
Group
Duke Energy
Michael Lowman
Yes
Yes
(1) Duke Energy agrees that the scope of the SAR should be limited to Disperse Generation only.
(1) PRC-004-WECC-1 should also be included in this SAR with the same justification provided for the NERC Standard PRC-004-2
(1) Duke Energy is concerned that Dispersed Generation will have to be compliant with the BES definition Phase 1 prior to the Implementation of this Project and the implementation of Phase 2 of the BES definition. (2) Financial implications to registered entities should be considered and included in the Industry Need section of the SAR such as additional human resources required to maintain compliance if the standards are not revised for the applicability of dispersed generation resources at the point of aggregation to 75 MVA or greater.
Group
DTE Electric
Kathleen Black
Yes
Yes
Yes As stated in the background information, any relevant standard should be revised as necessary to insure that it is being applied at the point of aggregation.
No
No
No
Individual

Scott Langston
City of Tallahassee
Yes
Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Yes
Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.
Yes
No
No
No
Individual
Carla L. Holly
BP Wind Energy North America Inc.
Yes
Yes
The scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources as dispersed generation resources are unique and have operational characteristics that are not similar to most conventional generators, including generators that are considered to be classified as small.
Yes. We agree with the list of standards to be reviewed; however, we suggest more clarification about which specific IRO, MOD, PRC, and TOP standards would be considered as the SAR currently lists these categories generically.
No.
No.
No.
Individual
Karen Webb
City of Tallahassee
Yes
Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Yes
Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as waste-to-energy, biogas, and biomass generation sources.
Group
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson

Yes
No
We believe the scope should include consideration of changes to standards applicability for all small generation. In particular, individual generators < 75 MVA should be exempted from model validation requirements unless transmission planning studies demonstrate such individual generators are critical to BES reliability. This would significantly reduce the compliance burdens being imposed on many GOs and GOPs and improve the focus on generators that are critical to reliability.
No. Need to also add those included in the Generator Verification Standard suite, including PRC-019, PRC-024, MOD-025, MOD-026, MOD-027. We are concerned with how certain standard requirements such as VAR-002 R3 can be applied to facilities with multiple “mini” units operating in parallel. For example, in the case of small turbine-generators one or more units operating in manual regulator mode would not have the same impact to the BES as a single large unit. Similar issues exist when some of the other listed standard requirements are applied such as model validation of excitation systems and governors (MOD-026 & MOD-027, as noted above).
No
No
No
Individual
Peter A. Heidrich
Florida Reliability Coordinating Council, Inc.
No
The SAR should not be limited to dispersed power producing resources only. A significant issue that will prove to derail this project is the potential inequitable treatment of generation. The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. Provisions with in the 'Applicability' of the appropriate Reliability Standards that take into account these types of units would significantly reduce the compliance obligations for units that simply are replaced (in whole)when a failure occurs.
No
The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. The reliability benefit of a generating facility is based on the MVA output of the unit, not on the fuel source or the prime mover force. Within a generating facility that aggregates to >75 MVA, there is no difference in the reliability benefit of a single wind turbine or a single gas fired turbine with the same MVA nameplate rating.
No
No
Group
Bonneville Power Administration
Andrea Jessup
Yes
No
(a) BPA feels that the term “dispersed generation resource” is typically associated with facilities that produce electric power through cogeneration and through renewable resources — such as biomass, solar, hydro, wind, municipal waste, tidal, wave, geothermal, and energy storage. It doesn’t matter which type of resource is used to generate power; what matters is the aggregated output at the

point of interconnection, which may have an effect on the electric power system. IEEE Standard 1001-1988 (IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems) and IEEE Standard 1547 (IEEE Standard for Interconnecting distributed Resources with Electric Power Systems) provide information regarding the technical aspects of dispersed generation resources. (b) BPA feels that for PRC-005 & PRC-023, the SAR needs to include individual turbine equipment dynamic response, such that the aggregate collector system provides the required relay response, not just the protective devices from the point of aggregation. It serves no reliability purpose if each turbine internally trips for a system event that requires continuation of the generation in a coordinated manner. (c) BPA feels that FAC-008 requires documentation from the generator to the high side of the main step-up transformer. For dispersed generation, this is the transformer at the main collector transformer. The SAR needs to consider including documentation for the collector system capability. BPA has found that when reactive current was not considered in earlier projects, overloads on some collectors were possible, which limited response to system events. (d) BPA has been requiring a collector system study provided by the generator owner to determine the reactive losses of the generation project and to ensure that reactive requirements are met. BPA has recently developed a collector system performance requirement to demonstrate compliance with reactive capability requirements. BPA recommends that this be added to the scope of the SAR to ensure that the generation in aggregate responds as required for a BES generation project.
No. BPA feels that a review of PRC-024 (Generator Frequency and Voltage Protective Relay Settings) needs to be included in the scope of this SAR. Aggregated dispersed generation must be able to ride-through faults and system disturbances the same as other generation resources.
No.
No.
Yes. IRO, MODs TOPs should be reported in aggregate. Outage coordination requirements for non-dispatchable generation should be eased as the certainty of the generation is never precisely known. BPA feels focusing compliance activities at the point of aggregation to 75 MVA is acceptable; however, there are a couple areas where we need to be cautious. One area of concern is the issue of back feed. Regardless of the size of the dispersed generation resource, proper precautions must be in place to ensure that it does not unintentionally or unexpectedly feed back into the BES. This is a matter of safety for personnel who might be doing construction or maintenance activities on the BES. BPA’s other area of concern is the ability of the dispersed resources to ride through faults and system disturbances. BPA’s concern here is similar to the concern BPA had when large amounts of wind generation began to be integrated into the grid. Specifically, BPA is concerned that the settings on protection schemes might be set such that large numbers of them would drop off during an event. This would be the equivalent of a large, high-speed spike in load, which could make the event far worse.

Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources

The Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) standards drafting team (SDT) thanks all commenters who submitted comments on the Standard Authorization Request (SAR) for this project. The SAR was posted for a 30-day formal comment period from November 20, 2013 through December 19, 2013. Stakeholders were asked to provide feedback on the SAR through a special electronic comment form. There were 28 sets of comments, including comments from approximately 98 different commenters from approximately 60 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the DGR project page.

The DGR SDT has carefully reviewed and considered each stakeholder comment in developing this summary response. In addition, the DGR SDT notes that it will not propose changes to the SAR because it believes the objectives of this project can be adequately addressed within the scope of the SAR.

1. General Scope and Objective of the SAR

Some commenters disagree with the scope and objective of the SAR because they believe, for example, that the Bulk Electric System (BES) definition has addressed the concerns raised in the SAR, and that the SAR is therefore not necessary. The DGR SDT disagrees. While the BES definition has identified certain dispersed power producing resources and their aggregating equipment relative to their inclusion as BES Facilities, it does not take into account that in order to maintain reliability of the BES and ensure appropriate use by entities of compliance and maintenance resources, certain reliability standards and their requirements should not or cannot be applied to dispersed generating facilities in the same manner as traditional generating resources. The SAR is therefore necessary to ensure that the facilities of dispersed generation resources are appropriately assigned responsibility for requirements that actually impact the reliability of the BES, as the characteristics of operating dispersed generation can be unique.

Some commenters would like to include standards not specifically identified in the SAR, for example, certain CIP, FAC, IRO, MOD, PRC, and TOP standards. The DGR SDT agrees that all NERC Standards should be reviewed as part of this project to determine whether changes are justified in order to account for the unique characteristics of dispersed generation, and has undertaken such a review. This review includes standards that are directly applicable to dispersed generation resources. For many standards, the concerns related to applicability to dispersed generation may be resolved through the publication of NERC guidance documentation in lieu of changes to the language of existing or future reliability standards. The DGR SDT expects that the concerns with the majority of the standards will be addressed through this manner.

Some commenters note that the scope of the SAR should be expanded to include all small generators regardless of types. As noted in the SAR, the DGR SDT will consider those resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a collector system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. The DGR SDT believes that the scope of the current SAR allows for consideration of various generation designs when determining their impact upon the reliability of the BES. However, the DGR SDT notes that the impact that dispersed power producing resources (as described in the BES Definition reference document) could potentially have on the reliability of the BES is not necessarily the same impact that a traditional generator, regardless of size, will have, and must account for these differences when considering the applicability of any specific standard requirements.

At least one commenter suggested that for PRC-005 and PRC-023, the SAR needs to include individual turbine equipment dynamic response, such that the aggregate collector system provides the required relay response, not just the protective devices from the point of aggregation. The DGR SDT understands that there are certain reliability standards that may require applicability on Facilities below the point of aggregation at 75 MVA nameplate rating and is considering these functions in reviewing the applicability of specific requirements.

At least one commenter stated that the SAR does not make a coherent technical case for any standards changes. The DGR SDT will evaluate the merits of any proposed changes to the standards within the scope of the SAR and will seek to provide a detailed justification for proposed changes.

At least one commenter made suggestions to improve clarity of the SAR, e.g., changes to the "Industry Need" and "SAR Information" sections of the SAR. The DGR SDT will take those comments into account during the evaluation process to address the goals of this project and the revisions that are recommended.

The DGR SDT acknowledges that a number of comments support the initial scope of the SAR, with some additional recommendations regarding applicability. The DGR SDT feels that the scope of the current SAR allows for consideration of various generation designs when determining their impact upon the reliability of the BES.

2. BES Definition and Transition Period

At least one commenter expressed concern about the transition period for implementation of the BES definition and this project. The DGR SDT gives due consideration to the timing associated with compliance requirements to include transition periods. This will encompass the transitional period associated with the BES definition.

The DGR SDT notes that the project schedule has been developed to take into account the July 1, 2016 compliance obligation date associated with the revised BES definition.

The DGR SDT also notes that it is focused on reliability in evaluating the standards but will remain mindful of the financial implications of compliance.

Some commenters suggest that the BES definition should be revised. The DGR SDT will not re-evaluate the BES definition, as it is beyond the scope of this project. The goal of the SAR is to revise the applicability of GO/GOP Reliability Standards or the applicability of requirements in GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the revised definition of the BES.

3. Canadian Provincial or other Regulatory Requirements

At least one commenter stated that there may be state regulatory requirements established for dispersed generation that may need to be considered in this project. The DGR SDT can make recommendations to Regional Entities that have approved Regional Reliability Standards; however, the DGR SDT cannot change those regional standards. Responsible entities may in fact be subject to additional regulatory requirements but such requirements are outside of NERC's sanctioned enforcement authorities and cannot be addressed in this process, but may be considered.

At least one commenter raised concerns about Quebec registration requirements. The DGR SDT does not believe it needs to specifically address the registration criteria of Canadian provinces. Although Quebec has unique registration values, it should not impact standard applicability.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you may contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Jeffrey Delgado	Caithness Shepherds Flat, LLC					X					
No Additional Responses													
2.	Group	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
No Additional Responses													
3.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	2
2.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
3.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
4.	Mike Kidwell	Empire District Electric	SPP	1
5.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
6.	Shannon Mickens	Southwest Power Pool	SPP	2
7.	Katy Onnen	Kansas City Power & Light	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21.	Brian Robinson	Utility Services	NPCC	8
22.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
23.	Brian Shanahan	National Grid	NPCC	1
24.	Wayne Sipperly	New York Power Authority	NPCC	5
25.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
26.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Russel Mountjoy	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

2.	Chuck Wicklund	OtterTail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
7.	Joseph DePoorter	Madision Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	Midcontinent Independent System Operator	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
14.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Greg Campoli	ISO/RTO Council Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kathleen Goodman	ISO-NE	NPCC	2
2.	Cheryl Moseley	ERCOT	ERCOT	2
3.	Al DiCaprio	PJM	RFC	2
4.	Terry Bilke	MISO	MRO	2
5.	Charles Yeung	SPP	SPP	2
6.	Ben Li	IESO	NPCC	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Jackson	Buckeye Power, Inc.	RFC	3, 4
2.	Alisha Anker	Prairie Power, Inc.	SERC	3
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
4.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
5.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

				1	2	3	4	5	6	7	8	9	10
9.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Regulated Marketing	RFC	5
4.	Barbara Holland		RFC	
5.	Neil Kennings		RFC	

				1	2	3	4	5	6	7	8	9	10
10.	Group	Wayne Johnson	Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				

No Additional Responses.

				1	2	3	4	5	6	7	8	9	10
11.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Anasis	Transmission Technical Operations	WECC	1
2.	Richard Becker	Transmission Substation Engineering	WECC	1
3.	Stephen Enyeart	Transmission Customer Service Engineering	WECC	1
4.	Fred Ojima	Transmission Planning	WECC	1
5.	Chuck Sheppard	Transmission Vegetation/Access Road Mgmt	WECC	1

				1	2	3	4	5	6	7	8	9	10
12.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
13.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
14.	Individual	Patricia Metro	National Rural Electric Cooperative Association	X		X	X						
15.	Individual	David Jendras	Ameren	X		X	X	X					
16.	Individual	Silvia Parada Mitchell	NextEra Energy	X		X		X	X				
17.	Individual	Jonathan Meyer	Idaho Power	X									
18.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
19.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
20.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
21.	Individual	Chris Scanlon	Exelon	X		X	X	X	X				
22.	Individual	David Greyerbiehl	Consumers Energy Company			X		X					
23.	Individual	Gary Kruempel	MidAmerican Energy Company	X		X		X	X				
24.	Individual	Bill Fowler	City of Tallahassee (TAL)			X							
25.	Individual	Scott Langston	City of Tallahassee	X									
26.	Individual	Carla L. Holly	BP Wind Energy North America Inc.					X					
27.	Individual	Karen Webb	City of Tallahassee					X					
28.	Individual	Peter A. Heidrich	Florida Reliability Coordinating Council, Inc.										X

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Agree	Supporting Comments of "Entity Name"
NextEra Energy	Agree	MidAmerican
MidAmerican Energy Company		These comments were developed by NextERA (contact Brian Murhpy), MidAmerican, and Exelon

1. **Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.**

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 1 Comment
National Rural Electric Cooperative Association	No	NRECA does not believe this SAR is necessary. If entities with dispersed generation are registered as a Generator Owner (GO)/Generator Operator (GOP), it is the obligation of the registered entity to determine applicable standards and associated requirements and be able to explain how it complies accordingly. There is no need to modify the applicability of standards to specifically recognize dispersed generation as there is no recognizable reliability gap with the existing applicability of the standards included in this SAR.
Idaho Power	No	The BES definition in process has addressed the concerns raised in the SAR (in our opinion). Application of Standards applies to BES elements unless specifically excluded.
Public Service Enterprise Group	No	The SAR relies upon the phase 2 BES definition, as recently approved by the ballot body, but which has yet to be approved by the NERC Board or FERC. Under this definition, traditional generators at a site that exceed 75 MVA in aggregate as well as the all the equipment from terminals of each generator to the connection point with the BES are included in BES. Dispersed generators are treated differently. The individual dispersed generators are part of the BES if they are at a site where their aggregate nameplate capacity exceeds 75 MVA and they are connected to the BES; however, only equipment that delivers capacity from the point where those resources aggregate to greater than 75 MVA are included in the BES. Stated differently, traditional generators are contiguous with the BES, from the individual BES generators to their connection to the BES. Dispersed generators are not contiguous with the BES - the equipment that aggregate their output prior to it exceeding 75 MVA is excluded. These exclusions create a gap between dispersed BES generators and the BES they connect to. All generators should be treated comparably. The Eastern Interconnection Reliability

Organization	Yes or No	Question 1 Comment
		Assessment Group (ERAG) manual supports our recommendation regarding inclusion equipment for dispersed generators. Wind farm modeling, as specified in the ERAG manual, (https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Documents/MMWG%20Procedure%20Manual%20V10.pdf) requires a high level of detail - see p. 30, item 6, which states: "Wind Farms - Include all 34.5 kV collector bus(es) and the main facility step-up transformer(s) from 34.5 kV to transmission voltage, as well as one 0.600 kV (or whatever the wind generator nominal voltage is) level bus off each collector bus with a lumped generator and lumped GSU representing the aggregate of the wind turbines attached to that collector bus and their GSUs." Thus, the ERAG manual requires modeling of non-BES Elements under phase 2 BES definition - see the BES Webinar slides nos. 5-7. (http://www.nerc.com/pa/Stand/WebinarLibrary/bes_phase2_third_posting_20131010_webinar_final.pdf) Setting aside our phase 2 definition concerns, the SAR does not make a coherent technical case for any standards changes. As an example, the justification for a change in PRC-005-2 has contradicting statements: "Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level." In the first sentence, it appears that manufacturers install protection and control equipment at the "dispersed generation turbine and panel level," yet the next sentence states that "it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level." Which is it?During the balloting of PRC-005-2, no comments were submitted to the drafting team regarding the changes proposed in the SAR for PRC-005-2. Yet only a year after the final ballot on PRC-005-2, the SAR proposes changes to PRC-005-2 (and other standards) because the phase 2 definition, according to the SAR, would result in BES equipment at "dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES." We believe that dispersed generators will have less equipment, not more, under the proposed BES definition because of the excluded equipment under that definition. Finally, there has been no justification put forth that would justify different

Organization	Yes or No	Question 1 Comment
		treatment of dispersed generation from traditional generation. See our remarks in questions 2 and 6 below.
Wisconsin Electric Power Company	No	The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011.Addtionally, these standards need to be listed:PRC-001/027 - Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 - In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many.PRC-019 - Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard.MOD 012/032 - In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many.MOD 025 & 026 and 027 - In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.
Florida Reliability Coordinating Council, Inc.	No	The SAR should not be limited to dispersed power producing resources only. A significant issue that will prove to derail this project is the potential inequitable treatment of generation. The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. Provisions with in the 'Applicability' of the appropriate Reliability Standards that take

Organization	Yes or No	Question 1 Comment
		into account these types of units would significantly reduce the compliance obligations for units that simply are replaced (in whole)when a failure occurs.
ACES Standards Collaborators	Yes	We find this SAR timely and necessary to avoid confusion in the application of the revised definition of the Bulk Electric System.
MRO NERC Standards Review Forum	Yes	The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
American Electric Power	Yes	AEP would prefer that the solution for applicability of dispersed generation at the turbine or generating unit level would be by adjusting the BES definition accordingly. Creating a new SAR, allowing this topic be discussed within the framework of the BES definition itself, would seem the most direct and efficient way of debating the topic. However, if that cannot be accomplished, AEP supports the effort of this SAR as an alternative (though less desirable) means to accomplish the same goal.
Ameren	Yes	(1) The proposed SAR appears to advocate the GSU as the Element within these standards' applicability, which appears reasonable for a SAR. However, we believe that this conflicts with the BES Definition Phase 2 Reference figures. Our expectation is that the BES Definition would be included in the scope of this SAR.
Xcel Energy	Yes	We strongly support the objective of this SAR.
Exelon	Yes	The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.

Organization	Yes or No	Question 1 Comment
MidAmerican Energy Company	Yes	The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
City of Tallahassee (TAL)	Yes	Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
City of Tallahassee	Yes	Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
City of Tallahassee	Yes	Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Caithness Shepherds Flat, LLC	Yes	
Arizona Public Service Company	Yes	
SPP Standards Review Group	Yes	
Northeast Power Coordinating Council	Yes	
ISO/RTO Council Standards Review Committee	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
DTE Electric	Yes	
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Bonneville Power Administration	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
BP Wind Energy North America Inc.	Yes	

2. Do you agree that the scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources, or should the scope encompass consideration of changes to standards applicability for all small generation regardless of type? Please provide a technical rationale for your response.

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	No	Scope should expanded to include all small generators regardless of types. There is no specific reason to not include all. Generally, there is little reliability benefits to BES by applying NERC standards to small generators regardless of the type.
SPP Standards Review Group	No	We believe that this evaluation should be extended to all small generation regardless of type because the impact on the BES would be the same regardless of the source or prime mover of the generation.
ACES Standards Collaborators	No	No, we do not agree that the scope of the SAR should be limited. The scope of the SAR should be to review standards applicable to GO/GOP and to limit the applicability based on the revised definition of the BES. Small generation regardless of type should be included in this review.
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	No	We believe the scope should include consideration of changes to standards applicability for all small generation. In particular, individual generators < 75 MVA should be exempted from model validation requirements unless transmission planning studies demonstrate such individual generators are critical to BES reliability. This would significantly reduce the compliance burdens being imposed on many GOs and GOPs and improve the focus on generators that are critical to reliability.

Organization	Yes or No	Question 2 Comment
Generation and Energy Marketing		
Bonneville Power Administration	No	(a) BPA feels that the term “dispersed generation resource” is typically associated with facilities that produce electric power through cogeneration and through renewable resources - such as biomass, solar, hydro, wind, municipal waste, tidal, wave, geothermal, and energy storage. It doesn’t matter which type of resource is used to generate power; what matters is the aggregated output at the point of interconnection, which may have an effect on the electric power system. IEEE Standard 1001-1988 (IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems) and IEEE Standard 1547 (IEEE Standard for Interconnecting distributed Resources with Electric Power Systems) provide information regarding the technical aspects of dispersed generation resources.(b) BPA feels that for PRC-005 & PRC-023, the SAR needs to include individual turbine equipment dynamic response, such that the aggregate collector system provides the required relay response, not just the protective devices from the point of aggregation. It serves no reliability purpose if each turbine internally trips for a system event that requires continuation of the generation in a coordinated manner.(c) BPA feels that FAC-008 requires documentation from the generator to the high side of the main step-up transformer. For dispersed generation, this is the transformer at the main collector transformer. The SAR needs to consider including documentation for the collector system capability. BPA has found that when reactive current was not considered in earlier projects, overloads on some collectors were possible, which limited response to system events.(d) BPA has been requiring a collector system study provided by the generator owner to determine the reactive losses of the generation project and to ensure that reactive requirements are met. BPA has recently developed a collector system performance requirement to demonstrate compliance with reactive capability requirements. BPA recommends that this be added to the scope of the SAR to ensure that the generation in aggregate responds as required for a BES generation project.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	We believe it is preferable, at least initially, for the scope to remain limited to dispersed generation resources.
National Rural Electric Cooperative Association	No	See response to Question 1
Idaho Power	No	I see no need for a SAR.
Public Service Enterprise Group	No	As stated previously, "small generators" (traditional versus dispersed) are not treated comparably in the phase 2 definition - traditional BES generators must be contiguous with the BES but dispersed generators need not be. While we would welcome changes that provide for comparable treatment for small generators, regardless of type, the unequal treatment embedded in the phase 2 definition must be corrected before those changes are considered.
Florida Reliability Coordinating Council, Inc.	No	The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. The reliability benefit of a generating facility is based on the MVA output of the unit, not on the fuel source or the prime mover force. Within a generating facility that aggregates to >75 MVA, there is no difference in the reliability benefit of a single wind turbine or a single gas fired turbine with the same MVA nameplate rating.
Caithness Shepherds Flat, LLC	Yes	Caithness Shepherds Flat Wind Farm (CSF), located in Oregon, supports the SAR as written and believes the scope should address dispersed generation resources with collector systems only. In the development of CSF's NERC compliance program, it became apparent that some GO/GOP applicable Reliability Standards were written with fossil fuel facilities in mind, and not generation resources such as wind. The VAR-002 standard for example, requiring reactive and voltage control of individual generators and notification of the TOP when there is a change in status, would appear to be irrelevant to the TOP, but rather the aggregate MW output at the point

Organization	Yes or No	Question 2 Comment
		of interconnection should be what is relevant. CSF's wind farm consists of several hundred wind turbines, all < 3 MW in nameplate capacity. The TOP does not need to be notified about individual turbine voltage status, as any loss of voltage control of an individual turbine will not be detected by the TOP. The relevant factor is in the voltage at the point of interconnection which is controlled by a "Wind Farm Management System" WFMS voltage control system. Change in status of the WFMS would be of interest to the TOP, so the standard should allow for this variance.
MRO NERC Standards Review Forum	Yes	The SAR does not specify what types of generation should be included for analysis as "dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
ISO/RTO Council Standards Review Committee	Yes	Small generators that do not meet the individual 20 MVA criteria and are not part of the aggregated 75 MVA group that meets the BES inclusion criteria are not regarded BES facilities and therefore do not need to be addressed by this SAR. The scope therefore does not need to be expanded to all small generators.
Duke Energy	Yes	(1) Duke Energy agrees that the scope of the SAR should be limited to Disperse Generation only.
MidAmerican Energy Company	Yes	The SAR does not specify what types of generation should be included for analysis as "dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
City of Tallahassee (TAL)	Yes	Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.

Organization	Yes or No	Question 2 Comment
City of Tallahassee	Yes	Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.
BP Wind Energy North America Inc.	Yes	The scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources as dispersed generation resources are unique and have operational characteristics that are not similar to most conventional generators, including generators that are considered to be classified as small.
City of Tallahassee	Yes	Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as waste-to-energy, biogas, and biomass generation sources.
Exelon	Yes	Yes, the SAR should focus on generation resources that are part of a facility that aggregates dispersed resources at 75 MVA or more. We believe the intent is to exclude individual units from certain requirements when those units do not meet the reporting criteria but are part of a facility that aggregates those units at the BES voltage level. We note that the question may lead to confusion. As written the use of "or" appears to be implying there is a choice between "dispersed generation" as used in the first clause of the question and some generation "types" (undefined but commonly understood to refer to fuel source) as used in the second clause. We do not believe the SAR should exclude generation based on fuel type.
DTE Electric	Yes	
Manitoba Hydro	Yes	
Ameren	Yes	
Consumers Energy Company	Yes	

3. Do you agree with the list of standards to be reviewed? If you do not agree, please note specific standards you think should be added to or removed from the list.

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 3 Comment
American Electric Power	Every standard that involves the GO and/or GOP should be included in the scope of the SAR. This does not imply that all standards should be modified, but the SDT and commenters should be afforded the opportunity to consider the impacts of such changes. For example, PRC-024, PRC-001, CIP-002 through CIP-011, etc. should be considered.
Public Service Enterprise Group	No comments
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No. Need to also add those included in the Generator Verification Standard suite, including PRC-019, PRC-024, MOD-025, MOD-026, MOD-027. We are concerned with how certain standard requirements such as VAR-002 R3 can be applied to facilities with multiple "mini" units operating in parallel. For example, in the case of small turbine-generators one or more units operating in manual regulator mode would not have the same impact to the BES as a single large unit. Similar issues exist when some of the other listed standard requirements are applied such as model validation of excitation systems and governors (MOD-026 & MOD-027, as noted above).
Bonneville Power Administration	No. BPA feels that a review of PRC-024 (Generator Frequency and Voltage Protective Relay Settings) needs to be included in the scope of this SAR. Aggregated dispersed generation must be able to ride-through faults and system disturbances the same as other generation resources.

Organization	Question 3 Comment
Wisconsin Electric Power Company	Response from Q1:The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011.Addtionally, these standards need to be listed:PRC-001/027 - Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 - In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many.PRC-019 - Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard.MOD 012/032 - In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many.MOD 025 & 026 and 027 - In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.
National Rural Electric Cooperative Association	See response to Question 1
MRO NERC Standards Review Forum	The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The

Organization	Question 3 Comment
	reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
Exelon	The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate.
MidAmerican Energy Company	The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
ACES Standards Collaborators	We agree with the list of standards to be reviewed. We would like to see flexibility in the scope of standards to be reviewed in the event that another standard is added during the standards development phase.
Xcel Energy	We believe that in addition to the approved standards mentioned in the SAR, NERC should communicate this issue directly to drafting teams working on active projects such as PRC-004-3 or PRC-027-1 to assure that they consider the applicability of their standard relative to dispersed generation and, if it is intended to include dispersed generation as in scope, to assure that correct

Organization	Question 3 Comment
	terminology is used within their draft standard to avoid ambiguity and inconsistencies such as the SAR discusses for use of the term "main step up transformer" in FAC-008-3.
SPP Standards Review Group	While we may agree with the list of standards as presented in the SAR we would encourage the SAR drafting team to not limit itself to just those particular standards. For example, once a drafting team is established and work begins on the project, we don’t want the project to be limited by the scope as currently defined in the SAR. We need to factor in some flexibility to go beyond this specific list to capture all those standards/requirements/definitions which may be impacted in this review.
Caithness Shepherds Flat, LLC	Yes
Arizona Public Service Company	Yes
ISO/RTO Council Standards Review Committee	Yes
Consumers Energy Company	Yes
City of Tallahassee (TAL)	yes
City of Tallahassee	Yes
Ameren	Yes, we agree.
Northeast Power Coordinating Council	Yes.

Organization	Question 3 Comment
BP Wind Energy North America Inc.	Yes. We agree with the list of standards to be reviewed; however, we suggest more clarification about which specific IRO, MOD, PRC, and TOP standards would be considered as the SAR currently lists these categories generically.
DTE Electric	YesAs stated in the background information, any relevant standard should be revised as necessary to insure that it is being applied at the point of aggregation.

4. **Are you aware of any business practice that will be needed or that will need to be modified as a result of this SAR should it move forward? If yes, please identify the business practice.**

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 4 Comment
Caithness Shepherds Flat, LLC	No
Arizona Public Service Company	No
ISO/RTO Council Standards Review Committee	No
DTE Electric	No
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No
Manitoba Hydro	No

Organization	Question 4 Comment
Idaho Power	No
Exelon	No
MidAmerican Energy Company	No
City of Tallahassee	No
Florida Reliability Coordinating Council, Inc.	No
Public Service Enterprise Group	No comments
Northeast Power Coordinating Council	No.
ACES Standards Collaborators	No.
Bonneville Power Administration	No.
American Electric Power	No.
BP Wind Energy North America Inc.	No.
City of Tallahassee (TAL)	No. The City of Tallahassee is not aware of other business practices to be included.
SPP Standards Review Group	Not at this time.

Organization	Question 4 Comment
Consumers Energy Company	The SAR is required at a minimum, but a change to the BES definition is more appropriate.From the comments below submitted during the BES, the BES definition should at minimum be modified to provide consistency between generating resources (I2) and dispersed power producing resources (I4). Generating resources are required to be 20MVA in order to be considered an BES element, while dispersed power producing resources have no size consideration as long as they meet the net total MVA. Consumers Energy has completed studies with an operating wind farms and the loss of individual resources makes no impact the BES. The addition of individual resources does not make improve reliability as they have no effect on the system.The SAR intention is to modify the individual standards to define the requirements for all the additional BES elements that are being added that are not presently addressed in the standards or are against the manufacturers recommendations. While this approach can be used, and is required if the BES definition is not changed. A better method would be to include dispersed power producing resources at a point in which the total affects the BES and not as individual units.Previous Comments on BES definition:The inclusion and the clarification of the inclusion seem to contradict each other. The highlight portion above seems to indicate inclusion only from the point of aggregation of 75MVA or above. This, in most Wind Park cases would include a collector bus but probably not individual wind turbines. However I4 seems to indicate that the case of a Wind Park that has a total aggregation of 75 MVA, all associated equipment including every individual wild turbine would be included. There is inconsistency.If and when Distributed Generation gains saturation is it our intent that whole neighborhoods or industrial parks be considered BES resources? Technical justification should be needed to include resources in the BES, not the other way around. Is there a real expectation that a single collector circuit containing ten, 1.2MW wind turbines can cause cascading or uncontrollable outages of the surrounding system? It is extremely doubtful. We can support the inclusion of equipment where the aggregation of 75 MVA or more connects to the Bulk Electric System at voltages of 100kv or greater. There is a clear indication here that a single contingency can remove the total of the capacity from the system where with this definition as proposed, that is simply not the case.

5. **Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.**

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 5 Comment
SPP Standards Review Group	Although we are not aware of any specific federal regulatory requirements, the drafting team needs to keep in mind that there may be state regulatory requirements established for dispersed generation that may need to be considered in this project.
Idaho Power	N/A
Caithness Shepherds Flat, LLC	No
Arizona Public Service Company	No
ISO/RTO Council Standards Review Committee	No
DTE Electric	No
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation;	No

Organization	Question 5 Comment
Southern Company Generation and Energy Marketing	
Manitoba Hydro	No
Exelon	No
Consumers Energy Company	No
MidAmerican Energy Company	No
City of Tallahassee	No
Public Service Enterprise Group	No comments
ACES Standards Collaborators	No.
Bonneville Power Administration	No.
American Electric Power	No.
BP Wind Energy North America Inc.	No.
City of Tallahassee (TAL)	No. The City of Tallahassee is not aware of such.

Organization	Question 5 Comment
Northeast Power Coordinating Council	Yes.It must be considered that the operating system in Quebec follows chapter R-6.01 An Act Respecting the Regie de L’Energie, which details:(1) an owner or operator of a facility with a capacity of 44 kV or more connected to an electric power transmission system;(2) an owner or operator of an electric power transmission system;(3) an owner or operator of a production facility with a capacity of 50 megavolt amperes (MVA) or more connected to an electric power transmission system;(4) a distributor with a peak capacity of over 25 megawatts (MW), whose facilities are connected to an electric power transmission system; and(5) a person who uses an electric power transmission system under an electric power transmission service agreement with the electric power carrier or with any other carrier in QuÃ©bec.

6. **Are there any other concerns with this SAR that haven't been covered in previous questions?**

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 6 Comment
Arizona Public Service Company	No
Caithness Shepherds Flat, LLC	No
City of Tallahassee	No
Consumers Energy Company	No
DTE Electric	No
Florida Reliability Coordinating Council, Inc.	No
ISO/RTO Council Standards Review Committee	No
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	No

Organization	Question 6 Comment
Generation and Energy Marketing	
ACES Standards Collaborators	No other concerns.
American Electric Power	No.
City of Tallahassee (TAL)	No.
Northeast Power Coordinating Council	No.
BP Wind Energy North America Inc.	No.
SPP Standards Review Group	Regarding the July 2016 deadline, the drafting team needs to be sure that this effort is complete in time for the industry to be ready by July 2016. We need to be sure that as the deadline approaches, compliance preparations aren't made and then un-made as a result of a modification to an existing standard which is impacted by this effort.In the 1st line of the 1st paragraph of the Industry Need section under SAR Information, we suggest replacing 'application' with 'applicability'.In the 5th line of the 1st paragraph of the Brief Description section under SAR Information, replace 'real time' with 'Real-time', the NERC Glossary term.In the 1st line of the FAC-008-3 paragraph under SAR Information, hyphenate step-up.In the next to last line of the General review of IROs, MODs, PRCs, TOPs paragraph, change 'uneeded' to 'unneeded'.
Public Service Enterprise Group	Section 303 of the NERC ROP addresses "Relationship between Reliability Standards and Competition." Item 1 states: "Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage." By not treating all generators comparably, the SAR violates item 1. Based upon this and our prior comments, we recommend that the SAR be rejected by the Standards Committee.

Organization	Question 6 Comment
Exelon	The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
	The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
MRO NERC Standards Review Forum	The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Bonneville Power Administration	Yes. IRO, MODs TOPs should be reported in aggregate. Outage coordination requirements for non-dispatchable generation should be eased as the certainty of the generation is never precisely known.BPA feels focusing compliance activities at the point of aggregation to 75 MVA is acceptable; however, there are a couple areas where we need to be cautious. One area of concern is the issue of back feed. Regardless of the size of the dispersed generation resource, proper precautions must be in place to ensure that it does not unintentionally or unexpectedly feed back into the BES. This is a matter of safety for personnel who might be doing construction or maintenance activities on the BES.BPA's other area of concern is the ability of the dispersed resources to ride through faults and system disturbances. BPA's concern here is similar to the concern BPA had when large amounts of wind generation began to be integrated into the grid. Specifically, BPA is concerned that the settings on protection schemes might be set such that large

Organization	Question 6 Comment
	numbers of them would drop off during an event. This would be the equivalent of a large, high-speed spike in load, which could make the event far worse.
	(1) Apply the Generator Site Boundary used in the BES Definition Reference (e.g. Figure I2-5) consistently for dispersed generation so that multiple GSU do not circumvent the 75MVA aggregate.(2) Develop a NERC Glossary definition for the term ‘dispersed generation’.
Duke Energy	(1) Duke Energy is concerned that Dispersed Generation will have to be compliant with the BES definition Phase 1 prior to the Implementation of this Project and the implementation of Phase 2 of the BES definition.(2) Financial implications to registered entities should be considered and included in the Industry Need section of the SAR such as additional human resources required to maintain compliance if the standards are not revised for the applicability of dispersed generation resources at the point of aggregation to 75 MVA or greater.
Manitoba Hydro	Although we do not have any concerns with this SAR, we have the following suggestions to improve clarity.(1) Industry Need - remove the words “Bulk Electric System” from the second paragraph to leave only the acronym, BES because this is the second instance of BES in the document. (2) SAR Information - capitalize ‘misoperation’ because it appears in the Glossary of Terms.

Draft White Paper

Proposed Revisions to the Applicability of NERC Reliability Standards
NERC Standards Applicability to Dispersed Generation Resources

Project 2014-01 Standards Applicability for Dispersed Generation Resources Standard Drafting Team

April 14, 2014

1 Table of Contents

2 Executive Summary

The purpose of this white paper is to provide background and technical rationale for proposed revisions to the applicability of several North American Electric Reliability Corporation (NERC) Reliability Standards or requirements. The goal of the NERC Project 2014-01 Standards Applicability for Dispersed Power Producing Resources[1] standard drafting team (SDT) is to ensure that the Generator Owners (GOs) and Generator Operators (GOPs) of dispersed generation resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System (BPS), as the characteristics of operating dispersed generation resources can be unique. In light of the revised BES definition approved by the Federal Energy Regulatory Authority (FERC) in 2014[2], the intent of this effort is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed generation resources, where the status quo does not create a reliability gap.

The SDT performed a review of all standards that apply to GOs and/or GOPs (listed in Appendix A) and determined how each standard requirement should be appropriately applied to dispersed generation resources and categorized as follows:

- The existing standard language was appropriate when applied to dispersed generating resources and does not need to be addressed;
- The existing standard language was appropriate when applied to dispersed generating resources but additional NERC guidance documentation is needed to clarify how to implement the requirements for dispersed generating resources; and
- The existing standard language needs to be modified in order to account for the unique characteristics of dispersed generation resources. This could be accomplished through the applicability section of the standard in most cases or, if required, through changes to the individual requirements.

From this review, there are three (3) standards in which the SDT feels immediate attention is required to provide direction to industry stakeholders as soon as feasible regarding how to appropriately direct compliance related preparations. These standards include:

- PRC-004-2.1a;
- PRC-005 (relevant versions)[3]; and
- VAR-002.

However, the SDT has recognized that many standards (listed in Appendix B) should have further review by the SDT to determine the necessity and the type of clarification or guidance to the applicability for dispersed generation resources. This necessity is based on how each standard requirement, as written, would apply to dispersed generation resources and the individual generating units at these facilities,

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[1] Although the BES definition uses the term "dispersed power producing resources," the SAR and the SDT also use the term "dispersed generation resources" and "DGR." For the purposes of this paper, these terms are interchangeable.
[2] Glossary of Terms Used in NERC Reliability Standards, updated March 12, 2014.
[3] Reliability Standard PRC-005 is currently being revised as part of Project 2007-17.1 – Protection System Maintenance and Testing – Phase 3, available here: http://www.nerc.com/pa/Stand/Pages/Project-2007-17_3-Protection-System-Maintenance-and-Testing-Phase-3.aspx.

considering the recently approved BES definition. The proposed resolutions could target the applicability language in the applicability section or in individual requirements. There may be other methods to ensure applicability is consistent throughout the Regions, including modifying Reliability Standard Audit Worksheet (RSAW) language or having guidance issued by NERC. These tools, among others, will be considered by the SDT throughout the work effort.

The technical section of this paper includes insight from the SDT review, including the history of standards applicability to dispersed generation resources, identification of any unique circumstances for dispersed power producing resources and current practices, as well as the SDT's categorization and corresponding technical justification.

This white paper is a living document. It is the intent of the SDT to modify this document over the course of this project to document the SDT's rationale and technical justification for each standard until the work of the SDT is complete.

3 Purpose

The purpose of this white paper is to provide background and technical rationale for proposed revisions to the applicability of several Reliability Standards[4] or requirements that apply to GOs and/or GOPs. The goal of the proposed applicability changes is to ensure that the GOs and GOPs of dispersed generation resources have clarity as to their responsibility for requirements that impact the reliability of the BPS, as the characteristics of operating dispersed generation can be unique. This clarity will be accomplished through revised applicability language in the standards, recommended changes to the RSAW, or recommendations for a reliability guideline or reference document.

This document lays out a common understanding of design and operational characteristics of dispersed generation resources, highlighting the unique features of dispersed generation resources. The recommendations identified in this document consider the purpose and time horizon of the standards and requirements, as well as the avoidance of applying requirements in a manner that has no significant effect on reliability.[5] This document provides justification of and proposes revisions to the applicability of Reliability Standards and requirements, both existing and in development, and should be considered guidance for future standard development efforts. However, please note that recommendations provided in this paper are subject to comment and further review and revision.

Note that while this paper may provide examples of dispersed generation resources, the concepts presented are not specific to any one technology. The DGR SDT in general has referenced the BES Reference Document, which also refers to "dispersed power producing resources." Although the BES definition uses the term "dispersed power producing resources," the Standard Authorization Request (SAR) and the SDT also use the term "dispersed generation resources." For the purposes of this paper, these terms are interchangeable.

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[4] Note that "Reliability Standard" is defined in the NERC Glossary as "approved by FERC," but that the DGR SDT reviewed approved and unapproved standards.

[5] *North American Electric Reliability Corporation*, 138 FERC ¶ 61,193 at P 81 (2012).

4 Background

By submitting a SAR to the NERC Standards Committee, industry stakeholders requested that the applicability of Reliability Standards or the requirements of Reliability Standards be revised to ensure that the Reliability Standards are not imposing requirements on dispersed generation resource components that are unnecessary or counterproductive to the reliability of the BPS. The SDT intends to ensure that Reliability Standards are applied to dispersed generation resources to support an effective defense-in-depth strategy and Adequate Level of Reliability for the reliability of the interconnected BPS.

For purposes of this effort, dispersed generation resources are those individual 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. This request is related to the approved definition of the BES from Project 2010-17,[6] which resulted in the inclusion of distinct components of dispersed generation resources.

4.1 BES Definition

The BES definition[7] includes the following inclusion criterion addressing dispersed generation resources:

> *I4. 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. Thus, the facilities designated as BES are:*
>
> > *a) The individual resources, and*
> > *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.*

Upon implementation of Inclusion I4, NERC standards and requirements applicable to Generator Owners and Generator Operators will apply to owners and operators of all of the components included in the definition, notably each individual generator of a dispersed generation resource facility in those requirements, except in certain standards that explicitly identify the applicable facilities or provide specific guidance on applicability to dispersed generation resources.

The *BES Definition Reference Document*[8] includes a description of what constitutes dispersed generation resource:

> *"Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power*

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[6] http://www.nerc.com/pa/Stand/Pages/Project2010-17_BES.aspx
[7] Glossary of Terms Used in NERC Reliability Standards, updated March 12, 2014. http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
[8] Bulk Electric System Definition Reference Document, Version 2, April 2014. http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_reference_document_20140325_final_clean.pdf.

system. Examples could include but are not limited to: solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells."

4.2 Dispersed Generation Resources

Dispersed generation resources are often considered to be variable energy resources such as wind and solar. This description is not explicitly stated in the BES definition; however, NERC and FERC characterize variable generation in this manner regarding the purpose of Inclusion I4 of the definition.[9]. Therefore, the SDT is considering the reliability impacts of variable generation that depends on a primary fuel source which varies over time and cannot be stored.[10] Reliably integrating high levels of variable resources – wind, solar, ocean, and some forms of hydro – into the BPS require significant changes to traditional methods used for system planning and operation.[11] While these resources provide challenges to system operation, these resources are instrumental in meeting government-established renewable portfolio standards and requirements that are based on vital public interests.[12]

4.2.1 Design Characteristics

For dispersed power producing resources to be economically viable, it is necessary for the equipment to be geographically dispersed. The generating capacity of individual generating modules can be as small as a few hundred watts to as large as several megawatts. Factors leading to this dispersion requirement include:

- Practical maximum size for wind generators to be transported and installed at a height above ground to optimally utilize the available wind resource;
- Spacing of wind generators geographically to avoid interference between units;
- Solar panel conversion efficiency and solar resource concentration to obtain usable output; and
- Cost-effective transformation and transmission of electricity.

The utilization of these small generating units results in a large number of units (e.g., several hundred wind generators or several million solar panels) installed collectively as a single facility that is connected to the transmission system.

Dispersed generation resources interconnected to the transmission system typically have a control system at the group level that controls voltage and power output of the facility. The control system is capable of recognizing the capability of each individual unit or inverter to appropriately distribute the contribution required of the facility across the available units or inverters. The variable generation control system must also recognize and account for the variation of uncontrollable factors such as wind speed and solar

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[9] NERC December 13, 2013 filing, page 15 (FERC Docket No. RD14-2); NERC December 13, 2013 filing, page 17 (FERC Docket No. RD14-2); NERC January 25, 2012 filing, page 18 (FERC Docket No. RD14-2), FERC Order Approving Revised Definition, Docket No. RD14-2-000, Issued March 20, 2014.

[10] "*Electricity Markets and Variable Generation Integration*", WECC, January 6, 2011. https://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/WECC%20Whitepaper%20-%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf

[11] "*Accommodating High Levels of Variable Generation*", NERC, April, 2009. http://www.nerc.com/files/ivgtf_report_041609.pdf

[12] *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 335, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

irradiance levels. Thus, for some standards discussed in this paper it is appropriate to apply requirements at the plant level rather than the individual generating unit.

4.2.2 Operational Characteristics

Dispersed generation resources often rely on a variable energy source (wind, for example) that is not able to be stored. Because of this, a facility operator cannot provide a precise forecast of the expected output to a Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC); however, short-term forecasting capability is improving and thus reducing uncertainty.[13] The forecasting and variable operating conditions are well understood by BAs, TOPs, and RCs as evidenced by the successful operation of these generating resources over the years. Dispersed generation resources by their nature result in each individual generating unit potentially experiencing varied power system parameters (e.g. voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities design.

Many older dispersed generation resources are limited in their ability to provide essential reliability services. However, due to technological improvements, new dispersed generation resources are capable of providing system support for voltage and frequency. For efficiency, the facilities are designed to provide the system requirements at the point of interconnection to the transmission system.

4.2.3 Reliability Impact

A dispersed generation resource is typically made up of many individual generating units. In most cases, the individual generating units are similar in design and from one manufacturer. The aggregated capability of the facility may in some cases contribute significantly to the reliability of the BPS. As such, there can be reliability benefits from ensuring the equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in certain applicable NERC standards. When evaluated individually, however, the individual generating units often do not provide a significant impact to BPS reliability, as the unavailability or failure of any one individual generating resource may have a negligible impact on the aggregated capability of the facility. The SDT acknowledges that FERC addressed the question of whether individual resources should be included in the BES definition in Order Nos. 773 and 773-A, and concluded that individual wind turbine generators should be included as part of the BES. The SDT is not challenging this conclusion, but rather is addressing the applicability of standards on a requirement-by-requirement basis as necessary to account for the unique characteristics of dispersed generation. Thus, the applicability of requirements to individual generating units may be unnecessary except in cases where a common mode issue exists that could lead to a loss of a significant number of units or the entire facility in response to a transmission system event.

4.3 Drafting Team Efforts

The SDT is approaching this project in multiple phases. First, after a thorough discussion of the new definition of the BES,the SDT reviewed each standard, as shown in Appendix A, at a high level to recommend changes that would promote consistent applicability for dispersed generation resources

[13] "*Electricity Markets and Variable Generation Integration*", WECC, January 6, 2011. https://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/WECC%20Whitepaper%20-%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf

through the entire set of Reliability Standards. This review provided the type of changes proposed, the justification, and priority. The SDT has documented its review in this white paper, which will be posted for stakeholder comment to gain consensus on which standards require applicability changes to ensure application to dispersed forms of generation is clear. The next phase will include revising standards where necessary, addressing high priority issues first, and supporting the balloting and commenting process. The SDT will maintain and update the white paper throughout the effort.

4.3.1 Scope of Standards Reviewed

Initially, the focus of the standards review was on standards and requirements applicable to GOs and GOPs. However, during discussions, a question was raised to the SDT whether consideration is necessary for other requirements that affect the interaction of a Balancing Authority (BA), Transmission Operator (TOP), or Reliability Coordinator (RC) with individual BES Elements. For example, a requirement that states "an RC shall monitor BES Elements" may unintentionally affect the RC operator due to the newly revised BES definition. As such, the SDT decided to take a high-level look at all standards adopted by the NERC Board of Trustees or approved by FERC to ensure this issue is not significant.

All standards that were reviewed are listed in Appendix A along with the status of the standards as of April 10, 2014. The fields in Appendix A include the following;

- List of standards (grouped by approval status)
- Approval status of the standards which include
    - Subject to Enforcement
    - Subject to Future Enforcement
    - Filed and Pending Regulatory Approval
    - Pending Regulatory Filing
    - Designated for Retirement (2 standards – MOD-024-1 and MOD-025-1 – officially listed as Filed and Pending Regulatory Approval but will be superseded by MOD-025-2)
    - Proposed for Remand (4 standards – IRO-001-3, IRO-005-4, TOP-002-3, and TOP-003-2 – officially listed as Filed and Pending Regulatory Approval but, as of April 10, 2014, proposed to be remanded)
- Indication of change or additional review necessary

The SDT also reviewed, at a high-level, any approved regional standards. In cases where a change is recommended to a regional standard, the SDT will notify the affected Region. In addition, the SDT is prepared to provide recommendations to other active NERC standard development efforts, where appropriate.

4.3.2 Reliability Principles

The SDT used the following Reliability Principles to review the standards:

- Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
- The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

- Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
- Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
- Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
- Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
- The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
- Bulk power systems shall be protected from malicious physical or cyber attacks.

4.3.3 Prioritization Methodology

The SDT established a prioritization for the review and modification of applicability changes recommended to NERC standards and requirements. The SDT evaluated each requirement to identify the appropriate applicability to support reliability of the BPS. After the SDT identified a standard or requirement where changes to the applicability are warranted, it performed a prioritization. In general, any standard or requirement in which the SDT believes modifications are required has been assigned a high, medium, or low priority. The standards and requirements priorities were established as follows:

- High priority was assigned if compliance-related efforts with no appreciable reliability benefit would require not only significant resources but also would require efforts to be initiated by an entity well in advance of the implementation date;
- Medium priority was assigned if significant effort and resources with no appreciable reliability benefit would be required by an entity to be compliant; and
- Low priority was assigned to other changes that may need to be made to further ensure requirements add to reliability, but are not perceived as a significant compliance burden.

The prioritization of each recommendation is identified in Appendix B.

- List of standards (grouped by priority)
- Approval status of the standards (same designations as used in Appendix A)
- Recommendation of changing the applicability section of the standard or by changing the applicability for specific requirements
- Recommendation of what level of applicability should apply (e.g., point of interconnection, point where generation aggregates to greater than 75 MVA, individual generating units)

5 Technical Discussion

This section provides a review of each group of standards, focusing on the impact of the BES definition on reliability and compliance efforts. This discussion proposes a resolution for each standard, whether it is a change in the applicability section or in a specific requirement, clarification in a guidance document, or no action needed.

Status	Number of Standards	Number of standards to be Addressed	Number of standards to be Changed
NERC Standards	**162**	**20**	**14**
Subject to Enforcement	99	9	8
Subject to Future Enforcement	19	6	3
Pending Regulatory Approval	29	5	3
Pending Regulatory Filing	9	0	0
Designated for Retirement	2	0	0
Proposed for Remand	4	0	0
Region-specific Standards (*Out of Scope)	**19**	**4**	**4**
Subject to Enforcement	16	3	3
Subject to Future Enforcement	1	1	1
Pending Regulatory Approval	2	0	0
Grand Total	**181**	**24**	**18**

5.1 BAL

The group of BAL standards focuses primarily on ensuring the Balancing Authority (BA) has the awareness, ability, and authority to maintain the frequency and operating conditions within its BA Area. Only two standards in this group affect GO and/or GOP, and no BAL standard reviewed affected the interaction of a host BA, TOP, or RC with individual BES Elements.

5.1.1 BAL-005 — Automatic Generation Control

The purpose of this standard, as it applies to GOPs, is to ensure that all facilities electrically synchronized to the Interconnection are included within the metered boundary of a BA Area so that balancing of resources and demand can be achieved. Ensuring the facility as a whole is within a BA Area ensures the individual units are included. *Therefore, the applicability of the BAL-005 standard does not need to be changed for dispersed generation resources.*

5.1.2 BAL-001-TRE-1 — Primary Frequency Response in the ERCOT Region

The purpose of BAL-001-TRE-1 standard is to maintain Interconnection steady-state frequency within defined limits. This standard should be modified to clarify the applicability for dispersed generation resources to the total plant level to ensure coordinated performance. However, this is a regional standard and not part of the SDT scope. *The SDT will communicate this recommendation to the relevant Region.*

5.2 COM[14]

The COM standards focus on communication between the RC, BAs, TOPs, and GOPs. The only requirements in any of the current or future enforceable standards that apply to the GOP are clearly intended to apply to the individual GOP registered functional entity (i.e., requires communication between GOPs, TOPs, BAs, and RCs), not the constituent Elements it operates. Consequently, there is no need to differentiate the GOPs obligation for dispersed generation resources from any other resources. *Therefore, the applicability of the COM-001-2, COM-002-2a, and COM-002-3 standards that were reviewed do not need to be changed for dispersed generation resources.*

5.3 EOP

The EOP standards focus on emergency operations and reporting. The standards that apply to GO and/or GOP entities are EOP-004 and EOP-005. No EOP standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

5.3.1 EOP-004 — Event Reporting

The purpose of this standard is to improve the reliability of the BES by requiring the reporting of events by Responsible Entities. The requirements of this standard that apply to the GO and GOP are clearly intended to apply to the individual GO and GOP registered functional entity, not the constituent Elements it operates. Moreover, reportable events identified in Attachment 1 could only apply at the plant level. There is no need to differentiate dispersed generation resources from any other GO and/or GOP resource. *Therefore, the applicability of EOP-004 does not need to be changed for dispersed generation resources.*

5.3.2 EOP-005 — System Restoration from Blackstart Resources

EOP-005 ensures plans are in place to restore the grid from a de-energized state. The requirements that apply to a GOP are primarily for individual generation facilities designated as Blackstart Resources, with one requirement to participate in restoration exercises or simulations as requested by the RC. The inclusion of Blackstart Resources is already identified in the BES definition through Inclusion I3. The expectation is that all registered GOPs will participate in restoration exercises as requested by its RC. *Therefore, the applicability of EOP-005 does not need to be changed for dispersed generation resources.*

5.4 FAC

The FAC standards focus on establishing ratings and limits of the facility and interconnection requirements to the BES. Several standards apply to GOs and/or GOPs. No FAC standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

5.4.1 FAC-001 — Facility Connection Requirements

Requirements R2 and R3 of this standard apply to any GO that has an external party applying for interconnection to the GO's existing Facility in order to connect to the transmission system. This scenario is uncommon and there is no precedent for applicability of this standard to dispersed generation resources known to the SDT. Current practice primarily includes the GO stating that they will comply with the standard if this scenario is ever realized. This standard allows the GO to specify the conditions that must

[14] Note that COM-002-2a and COM-002-3, which are Pending Regulatory Filing, will be replaced by COM-002-4.

be met for the interconnection of the third-party, thus providing inherent flexibility to tailor the requirements specifically for the unique needs of the Facility. Furthermore, in 2012, the NERC Integration of Variable Generation Task Force (IVGTF) provided some suggested changes[15] to this standard for the next version. The IVGTF report included modifying requirements to this standard as well as recommended guidance for considering integration of variable generation plants. The recommendations are technology neutral and independent of the type of generation. *For these reasons, the applicability of FAC-001 does not need to be changed for dispersed generation resources.*

5.4.2 FAC-002 — Coordination of Plans for New Facilities

The purpose of FAC-002 is to ensure coordinated assessments of new facilities. The requirement applicable to GOs requires coordination and cooperation on assessments to demonstrate the impact of new facilities on the interconnected system and to demonstrate compliance with NERC standards and other applicable requirements. The methods used to demonstrate compliance are independent of the type of generation and are typically completed at the point of interconnection. *Therefore, the applicability of FAC-002 does not need to be changed for dispersed generation resources.*

5.4.3 FAC-003 — Transmission Vegetation Management

The purpose of this standard is to ensure programs and efforts are in place to prevent vegetation-related outages. This standard applies equally to dispersed generation facilities and traditional Facilities in both applicability and current practices, as it pertains to overhead transmission lines of applicable generation interconnection Facilities. *Therefore, the applicability of FAC-003 does not need to be changed for dispersed generation resources.*

5.4.4 FAC-008 — Facility Ratings

FAC-008 ensures facility ratings used in the planning and operation of the BES are established and communicated. The facility ratings requirement has historically been applicable to dispersed power producing resources and current practices associated with compliance are similar to traditional generation facilities. There is inherent flexibility in the standard requirements for the GO to determine the methodology utilized in determining the facility ratings.

To identify the facility rating of a dispersed power producing resource the analysis of the entire suite of facility components is necessary to adequately identify the minimum and maximum Facility Rating and System Operating Limits, and thus there would be no differentiation between the compliance obligations between dispersed power producing resources and traditional generation. *Although The SDT believes the industry and Regions would benefit from additional guidance on FAC-008-3 R1 to achieve a uniform approach, the applicability of FAC-008 does not need to be changed for dispersed generation resources.*

5.5 INT

The INT standards provide BAs the authority to monitor power interchange between BA Areas. No INT standard is applicable to the GO or GOP, or affects the interaction of a host BA, TOP, or RC with

[15] http://www.nerc.com/files/2012_IVGTF_Task_1-3.pdf

individual BES Elements. *Therefore, the applicability of the INT standards do not need to be changed for dispersed generation resources.*

5.6 IRO

The IRO standards provide RCs their authority. There are three IRO Standards that apply directly to GO and/or GOP entities. There are three standards that apply to the interaction of the RC with individual BES Elements. No other IRO standard reviewed affected the interaction of a host BA, TOP, or RC with GOs and/or GOPs.

5.6.1 IRO-001 — Reliability Coordination — Responsibilities and Authorities[16]

The purpose of these standards and their requirements as applicable to a GOP is to ensure RC directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements, or cannot be physically implemented. If a GOP is unable to follow a RC directive they are to inform the RC immediately of such.

Directives from RCs have been traditionally applied to the dispersed power producing resource at the aggregate facility level when they are related to either active power or voltage, such as an output reduction or the provision of voltage support. When such directives are not specific to any one Element within the Facility, it is up to the GOP to determine the appropriate method to achieve the desired result of the directive consistent with other applicable NERC Reliability Standards. When an RC directive specifies a particular Element or Elements at the GOP's facility, it is the expectation and requirement that the GOP will act as directed, so long as doing so does not violate safety, equipment, or regulatory or statutory requirements or cannot be physically implemented. For example, a directive could specify operation of a particular circuit breaker at a GOP Facility. *For these reasons, the applicability of IRO-001 does not need to be changed for dispersed generation resources.*

5.6.2 IRO-005 — Reliability Coordination — Current Day Operations[17]

The purpose of this standard and its requirements as it relates to GOPs is to ensure when there is a difference in derived limits the BES is operated to the most limiting parameter. A difference in derived limits can occur on any Element and therefore any limitation of the applicability of this standard may create a reliability gap. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of IRO-005 does not need to be changed for dispersed generation resources.*

5.6.3 IRO-010 — Reliability Coordinator Data Specification and Collection

The purpose of this standard and its requirement(s) as it relates to GOs and GOPs is to ensure data and information specified by the RC is provided. As each RC area is different in nature, up to and including the tools used to ensure the reliability of the BPS, a 'one size fits all' approach is not appropriate. This Reliability Standard allows for the RC to specify the data and information required from the GO and/or

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[16] Note that IRO-001-3, which is adopted by the NERC BOT, was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

[17] Note that applicability to GOPs has been removed in IRO-005-4, which is adopted by the NERC BOT. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

the GOP, based on what is required to support the reliability of the BPS. *Therefore, the applicability of IRO-010 does not need to be changed for dispersed generation resources.*

5.7 MOD

The MOD group of standards ensures consistent modeling data requirements and reporting procedures. The MOD standards provide a path for Transmission Planners (TPs) and Planning Coordinators (PCs) to reach out to entities for specific modeling information, if required. The existing and proposed modeling standards are sufficient for modeling dispersed generation resources; however, due to the unique nature of dispersed generation resources and an effort to bring consistency to the models, *the SDT will consider the need to develop guidelines for dispersed generation resource modeling and therefore recommends consulting other groups, e.g., the NERC Planning Committee and the MOD-032 SDT, to determine if developing such guidelines would be valuable to support accuracy of modeling.*

5.7.1 MOD-010 — Steady-State Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-010 does not need to be changed for dispersed generation resources.*

5.7.2 MOD-012 — Dynamics Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-012 does not need to be changed for dispersed generation resources.*

5.7.3 MOD-024-1 — Verification of Generator Gross and Net Real Power Capability

This standard was established to ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2.[18] *Therefore, the applicability of MOD-024-1 does not need to be changed for dispersed generation resources.*

5.7.4 MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability

This standard was established to ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2. *Therefore, the applicability of MOD-025-1 does not need to be changed for dispersed generation resources.*

5.7.5 MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net Real and Reactive Power capability is available for planning models used to assess BES reliability. This standard is appropriate for and includes specific provisions for dispersed generation resources to ensure changes in capabilities are reported. *However, the SDT recommends developing guidance documentation to clarify*

[18] MOD-024-1 and MOD-025-1 are NERC BOT Adopted but not subject to enforcement. They are commonly followed as good utility practice.

the applicability to ensure the reporting needs align with the dispersed generation resource control point (often one control system for an entire Facility), independent of the point at which it connects to the BES.

5.7.6 MOD-026 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

This standard provides for verification of models and data for voltage control functions. This standard is appropriate for dispersed generation resources to ensure changes in control systems and capabilities are reported. *However, the SDT recommends clarifying the applicability to ensure the reporting needs align with the dispersed generation resource control point (often one control system for an entire Facility), independent of the point at which it connects to the BES.*

5.7.7 MOD-027 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

This standard was established to verify that the turbine/governor and frequency control model accurately represent generator unit Real Power response to system frequency variations. This standard is appropriate for dispersed generation resources to ensure changes in control systems and capabilities are reported. *However, The SDT recommends clarifying the applicability to ensure the reporting needs align with the dispersed generation resource control point (often one control system for an entire Facility), independent of the point at which it connects to the BES.*

5.7.8 MOD-032 — Data for Power System Modeling and Analysis

The MOD-032 standard was established to ensure consistent modeling data requirements and reporting procedures for the planning horizon cases. The nature of dispersed generation resources is a challenge in modeling the steady-state and dynamic electrical properties of the individual components (e.g. individual units, collector system, interconnection components, etc.).

Models for dispersed generation resources are typically unique for each facility and proprietary. Generic models exist for dynamic analysis that may provide the accuracy of a facility-specific model. Some sections of the MOD-032 Attachment 1 pertain to modeling individual units, which may not be feasible. *Although the applicability of MOD-032 does not need to be changed for dispersed generation resources, the SDT recommends guidance documentation to ensure consistency in application of this standard. Such guidance may also have relevance to MOD-033, as well as provide interim guidance prior to and during the implementation period for these standards.*

5.8 NUC

The requirements in standard NUC-001 — *Nuclear Plant Interface Coordination* individually define the applicability to Registered Entities, not to the Elements the entities own or operate. While it is unlikely any Elements that are part of a dispersed generating resource would be subject to an agreement required by this standard, limiting the applicability of this standard could create a reliability gap and thus, there is no need to differentiate applicability to dispersed generation resources. *Therefore, the applicability of the NUC standard does not need to be changed for dispersed generation resources.*

5.9 PER

The PER standards focus on operator personnel training. The only requirements in any of the current or future enforceable standards that apply to the GOP is requirement R6 in PER-005-2 – *Operations Personnel Training*, and it is clearly intended to apply to the individual GOP registered functional entity that controls a fleet of generating facilities, not the constituent Elements it operates. As such, there is no need to differentiate dispersed generation resources from any other GOP resources*. Therefore, the applicability of the PER standards do not need to be changed for dispersed generation resources.*

5.10 PRC

The PRC standards establish guidance to ensure appropriate protection is established to protect the BES.

5.10.1 PRC-001-1.1 — System Protection Coordination

Requirement R1 requires GOPs to be familiar with the purpose and limitations of Protection System schemes applied in their area. The recently approved changes to the BES definition extend the applicability of this requirement. Often this familiarity is provided to GOP personnel through training on the basic concepts of relay protection and how it is utilized. The basic relaying concepts utilized in protection on the aggregating equipment at a dispersed generating site typically will not vary significantly from the concepts used in Protection Systems on individual generating units.

Requirement R2 requires that GOPs report protective relay or equipment failures that reduce system reliability. Protective System failures occurring within a single individual generating unit at a dispersed generation resource will not have any impact on overall system reliability and thus it should not be necessary for GOPs to report these failures to their TOP and host BA. Only failures of Protection Systems on aggregating equipment have the potential to impact BPS reliability and may require notification. When interpreted as stated above, no related changes should be required to the existing PRC-001-1 standard, as the BES definition changes do not have an impact on these requirements.

Requirement R3 requires GOPs to coordinate new protective systems. Coordinating new and changes to existing protective relay schemes should be applied to aggregating equipment protection only if a lack of coordination could cause unintended operation or non-operation of an interconnected entity's protection, thus potentially having an adverse impact to the BPS. Existing industry practice is to share/coordinate the protective relay settings on the point of interconnect (e.g. generator leads, radial generator tie-line, etc.) and potentially the main step-up transformer, but not operating (collection) buses, collection feeder, or individual generator protection schemes, as these Protection Systems do not directly coordinate with an interconnected utility's own Protection Systems. Relay protection functions such as under and overfrequency and under and overvoltage changes are not applicable here since they are independent of the interconnected utility's protective relay settings and because setting criteria are defined in PRC-024.

Requirement R5 requires GOPs to coordinate changes in generation, transmission, load, or operating conditions that could require changes in the Protection Systems of others. A GOP of a dispersed generation resource should be required to notify its TOP of changes to generation, transmission, load, or operating conditions on an aggregate facility level.

Project 2007-06 – System Protection Coordination and Project 2014-03 – Revisions to TOP and IRO Standards are presently revising various aspects of this standard or addressing certain requirements in other standards. The reliability objective of requirement R3 and R4 will be addressed Project 2007-06, and requirements R2, R5, and R6 will be addressed by Project 2014-03.

For these reasons, the SDT recommends communicating these concerns to the Project 2007-06 and 2014-03 drafting teams, and modifying the applicability of this standard to address dispersed generation resources.

5.10.2 PRC-001-2 — System Protection Coordination

The concerns addressed with PRC-001-1.1b are removed in PRC-001-2, which is adopted by the NERC BOT. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-03 – Revisions to TOP and IRO Standards. *For this reason, the SDT recommends communicating the concerns with PRC-001-1.1 to the 2014-03 drafting team.*

5.10.3 PRC-002-NPCC-01— Disturbance Monitoring
PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting

Requirements related to installation of Fault/Disturbance monitoring and/or sequence of events (SOE) recording capabilities on generating units and substation equipment which meet regional specific criteria may require installation of these capabilities on the aggregating equipment at a dispersed generation resource facility, and also requires maintenance and periodic reporting requirements to their RRO. However, these requirements have been previously applicable to the aggregating equipment at these dispersed generation resources, and these capabilities are not required to be installed on the individual generating units. The BES definition changes have no direct impact on applicability of these standards to dispersed generation resources. *Therefore, the applicability of these standards does not need to be changed for dispersed generation resources.*[19]

5.10.4 PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Misoperation reporting per PRC-004 is currently a requirement applied on the aggregating equipment at applicable dispersed generation resource sites meeting BPS criteria. The continuation of this analysis and reporting on the aggregating equipment by dispersed generation resource owners can provide value to BPS reliability and should remain in place. However, based on the experience of the SDT, there is minimal impact to BPS reliability for analyzing, reporting and developing Corrective Action Plans for each individual generating unit that trips at a dispersed generation resource site, as the tripping of one or a small number of these units has no material impact to the BPS reliability.

Additionally, reporting of Misoperations on each individual generating unit may result in substantial and unnecessary burdens on both the dispersed generation resource owner and the Regional Entities that review and track the resulting reports and Corrective Action Plan implementations. The SDT recognizes that many turbine technologies do not have the design capability of providing sufficient data for an entity to evaluate whether a Misoperation has occurred. Furthermore, dispersed generation resources by their nature result in each individual generating unit potentially experiencing varied power system parameters

[19] *See* NPCC CGS-005.

(e.g., voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities design. This limits the ability to determine whether an individual unit correctly responded to a system disturbance.

The SDT concludes that it is not necessary under PRC-004 to analyze Protection System Misoperations affecting individual generating units of a dispersed generation resource, but is concerned with the potential for unreported Misoperations involving a common mode trip of several individual generating units. The SDT proposes requiring analysis for potential Misoperation of individual generating units, if a trip of greater than 75 MVA aggregate occurs in response to a system disturbance. The above consideration by the SDT will be closely tied to its analysis of the applicability of and potential modifications to PRC-024, which provides for voltage and frequency ride-through requirements for individual generating units. *The SDT recommends changing the applicability of this standard and will consider how a common mode failure which results in Misoperation of a large number of the individual generating units at a dispersed generation resource site may impact BPS reliability*.

5.10.5 PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

Dispersed generation resource sites typically would not be associated with a WECC Major Transfer Path or Remedial Action Scheme, and thus would not be affected by PRC-004-WECC-1. If a site were to be involved with one of these paths or schemes, it is likely that associated protection or RAS equipment would be located on the aggregating equipment rather than the individual generating units. As such, the BES definition changes may have an impact on applicability of this standard to dispersed generation resources. This standard should be modified to clarify the applicability for dispersed generation resources; however, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT will communicate this recommendation to the relevant Region.*

5.10.6 PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing
PRC-005-2— Protection System Maintenance
PRC-005-3 — Protection System and Automatic Reclosing Maintenance

The aggregated capability of the individual generating units may in some cases contribute to the reliability of the BPS; as such there can be reliability benefit from ensuring the collection system and other BES equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in PRC-005-1.1b. When evaluated individually, however, the generating units themselves do not have the same impact on BPS reliability as the system used to aggregate the units. The unavailability or failure of any one individual generating unit would have a negligible impact on the aggregated capability of the facility; this would be irrespective to whether the dispersed generation resource became unavailable due to occurrence of a legitimate fault condition or due to a failure of a control system, protective element, dc supply, etc.

The protection typically utilized in these generating units includes elements which would automatically remove the individual unit from service for certain internal or external conditions, including an internal fault in the unit. These units typically are designed to provide generation output at low voltage levels, (i.e., less than 1000 V). Should these protection elements fail to remove the generating unit for this scenario, the impacts would be limited to the loss the individual generating unit and potentially the next device upstream in the collection system of the dispersed generation resource. However, this would still only result in the loss of a portion of the aggregated capability of the facility, which would be equally likely to occur due to a scenario in which a fault occurs on the collection system.

Internal faults on the low voltage system of these generating units would not be discernible on the interconnected transmission systems, as this is similar to a fault occurring on a typical utility distribution system fed from a substation designed to serve customer load. It is important to note that the collection system equipment (e.g., breakers, relays, etc.) used to aggregate the individual units may be relied upon to clear the fault condition in both of the above scenarios, which further justifies ensuring portions of the BES collection equipment is maintained appropriately.

For this reason, activities such as Protection System maintenance on each individual generating unit at a dispersed generation facility would not provide any additional reliability benefits to the BPS, but maintenance on facilities that aggregate the generation to 75 MVA or more would. *PRC-005-2 and -3 require modifications to the Applicability section (Facilities) to indicate that maintenance activities should only apply on the aggregating equipment at or above the point where the aggregation reaches 75 MVA. PRC-005-1.1b requires the same changes to the applicability section along with the addition of the facilities section already found in PRC-005-2 and -3. Modification to PRC-005-1.1b are necessary given the lengthy transition to its successor standards.*

Reliability Standard PRC-005 is currently being revised as part of Project 2007-17.1 – Protection System Maintenance and Testing – Phase 3, *available here*: http://www.nerc.com/pa/Stand/Pages/Project-2007-17_3-Protection-System-Maintenance-and-Testing-Phase-3.aspx. Any proposed changes to the PRC-005 Reliability Standard will be coordinated with this project. Project 2007-17.1 is considering technical changes and Project 2014-01 will consider any applicability change.

5.10.7 PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding
PRC-006-SERC -1 — Automatic Underfrequency Load Shedding Requirements

The regional specific PRC-006 standards deviate from the PRC-006-1 standard in that they have specific requirements for GOs. In particular, the NPCC version requires that GOs set their underfrequency tripping to meet certain criteria to ensure reliability of the BPS. Typically a dispersed generation resource site may have underfrequency protection on both the aggregating equipment (i.e., collection buses or feeders) as well as the individual generating units. Were this standard only to apply to aggregating equipment, the net impact to the BPS should a system disturbance occur may still result in a loss of significant generating capacity should each of the individual generating units trip for the event. Therefore it may be appropriate to include the individual generating units at a dispersed generation resource site as subject to this standard. The standard could be interpreted this way as written, but further clarification in the standard language may be considered. While this standard may need to be modified to clarify the applicability for dispersed generation resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT will communicate this recommendation to the relevant Region.*

The SERC version of PRC-006 requires GOs to provide, upon request, certain under and overfrequency related setpoints and other related capabilities of the site relative to system disturbances. It may be appropriate to include the capabilities of the individual generating units at a dispersed generation resource site when providing this information; however, it may be sufficient to provide only the capabilities of a single sample unit within a site as these units are typically set identically. This would be in addition to any related capabilities or limitations of the aggregating equipment as well. This may be accomplished by providing clarifications in the requirements sections. While this standard may need to be modified to clarify the applicability for dispersed generation resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT will communicate this recommendation to the relevant Region.*

5.10.8 PRC-015 — Special Protection System Data and Documentation
PRC-016 — Special Protection System Misoperations
PRC-017 — Special Protection System Maintenance and Testing

Relatively few dispersed generating resources contain portions of or entire Special Protection Systems; however, they do exist and therefore need to be evaluated for applicability based on the revised BES definition. The vast majority of these SPSs involve the aggregating equipment (transformers, collection breakers, etc.) and not the individual generating units. The SPS are installed to protect the reliability of the BPS, and as such the aggregated response of the site (e.g., reduction in output, complete disconnection from the BES, etc.) is critical, not the response of individual generating units. *Therefore, the applicability of these standards does not need to be changed for dispersed generation resources.*

5.10.9 PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Dispersed generating resources typically utilize a site level voltage control scheme which will direct the individual generating units to adjust their output to meet the voltage requirements at an aggregate facility level. In these cases the individual generating units will simply no longer respond once they are "maxed out" in providing voltage or reactive changes, but also need to be properly coordinated with protection trip settings on the aggregating equipment to mitigate risk of tripping in this scenario. For those facilities that only regulate voltage at the individual unit, these facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. The applicability in PRC-019-1 (section 4.2.3) includes a "Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating)." *The SDT recommends guidance documentation to address applicability to dispersed generation resources.*

5.10.10 PRC-023— Transmission Relay Loadability

Dispersed generating resources in some cases contain facilities and Protection Systems that meet the criteria described in the applicability section (e.g., load responsive phase Protection System on transmission lines operated at 200kV or above); however, in the majority of cases these lines are radially connected to the remainder of the BES and will be excluded from the standard requirements if PRC-023-3 is approved.[20] While certain entities with dispersed generation resources are required to meet the requirements of PRC-023-2 on components of their aggregating equipment (e.g., main step-up transformers, interconnecting transmission lines) the standard is not applicable to the individual generating units. The BES definition changes have no direct impact on the applicability of this standard to

[20] FERC has proposed approving PRC-023-3 in its Notice of Proposed Rulemaking issued on March 20, 2014. *Docket No. RM13-19-000, RM14-3-000, Generator Relay Loadability and Revised Transmission Relay Loadability Reliability Standards.*

dispersed generation resources. T*herefore, the applicability of these standards does not need to be changed for dispersed generation resources.*

5.10.11 PRC-024— Generator Frequency and Voltage Protective Relay Settings

There is a technical basis to leave the applicability of this standard as-is, due to the fact that were the individual generating units at a dispersed generation resource excluded from this requirement, it is possible large portions or perhaps the entire aggregated output of a dispersed generation resource site may be lost during certain system disturbances, negatively impacting BPS reliability. The SDT has determined it is necessary to require that Protection Systems applied on both the individual generating units, as well as any aggregating facilities, are set within the "no-trip zone" referenced in the requirements to maintain reliability of the BPS. However, for the purpose of compliance evidence it may be sufficient to provide the settings of a single sample unit within a site as these units are typically set identically, rather than providing documentation for each individual unit. This would be in addition to any related settings implementation evidence for the aggregating equipment. *No changes are required; however, an RSAW or guidance should specify compliance evidence requirements.*

5.10.12 PRC-025— Generator Relay Loadability

The Protection System utilized on individual generating units at a dispersed generation facility may include load-responsive protective relays and thus would be subject to the settings requirements listed in this standard. Were this standard only to apply to aggregating equipment, the net impact to the BPS should a system disturbance occur, may be a loss of significant generating capacity should each of the individual generating units trip for the event. Therefore, it is appropriate to include the individual generating units at a dispersed generation resource site as applicable to this standard. However, for the purpose of compliance evidence it may be sufficient to provide the settings of a single sample unit within a site as these units are typically set identically, rather than providing documentation for each individual unit. This would be in addition to any related settings implementation evidence for the aggregating equipment. *No changes are required; however, an RSAW or guidance should specify compliance evidence requirements.*

5.11 TOP

The TOP standards provide TOPs their authority. There are four TOP standards that apply directly to GO and GOP entities. The TOP standards as they relate to GOs/GOPs ensure RCs and TOPs can issue directives to the GOP, and the GOP follows such directives. They also ensure GOPs render all available emergency assistance as requested. Finally, they require GO/GOPs to coordinate their operations and outages and provide data and information to the BA and TOP. No TOP standard refers to the interaction of a host BA, TOP, or RC with individual BES Elements.

5.11.1 TOP-001-1a — Reliability Responsibilities and Authorities

This standard as it applies to GOPs is reviewed at the requirement level, with only one change recommended.

5.11.1.1 Requirement R3

The purpose of requirement R3 as it relates to GOPs is to ensure the RC and TOP reliability directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow a RC or TOP reliability directive they are to inform the RC or TOP immediately of such. The requirement is applicable to the registered functional entity, not the constituent Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed generation resources from any other GOP resources, and no change to this requirement is needed.*

5.11.1.2 Requirement R6

The purpose of requirement R6 as it relates to GOPs is to ensure all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements. The requirement is applicable to the registered functional entity, not the constituent Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed generation resources from any other GOP resources, and no change to this requirement is needed.*

5.11.1.3 Requirement R7

The purpose of requirement R7 as it relates to GOPs is to ensure BES facilities are not removed from service without proper notification and coordination with the TOP and, when time does not permit such prior notification and coordination, notification and coordination shall occur as soon as reasonably possible. This is required to avoid burdens on neighboring systems. It should be noted that the purpose of this standard is to keep the TOP informed of all generating facility capabilities in case of an emergency. It is assumed that required notification and coordination from the GOP to the TOP would be done in real-time and through verbal communication media. The concern here is how to apply this to a dispersed generation resource facility. The SDT recommends that the GOP report at the aggregate facility level to the TOP any generator outage above 20 MVA for dispersed generation resource facilities. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition, which addresses only generating units greater than 20MVA.
- TOP-002-2.1b R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the facility (e.g. 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.
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Dispersed generation resource outages should be reported as X MW out of Y MW are available. *Therefore, the SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for generator outages greater than 20 MVA.*

5.11.2 TOP-001-2— Transmission Operations

The purpose of this standard as it relates to GOPs is to ensure TOP directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow a TOP directive they are to inform the TOP immediately of such. It directs the TOP to issue directives and as such the TOP may provide special requirements for dispersed generation resources for its unique capabilities. Note that while this standard is adopted by the NERC BOT, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-03 – Revisions to TOP and IRO Standards. *The SDT recommends that Project 2014-3 provide direction for a dispersed generation resource to be only reported at the aggregate facility level. If TOP-001-1a R7 is reintroduced, then the recommendation provided above should be included in their efforts.*

5.11.3 TOP-002-2.1b — Normal Operations Planning[21]

This TOP standard has five requirements applied to GOPs. Several modifications are recommended below, and the SDT recommends that the most effective and efficient way to accomplish this is through modification of the Applicability section of this standard.

5.11.3.1 Requirement R3

The purpose of requirement R3 as it relates to GOPs is to ensure a GOP's current day, next-day and seasonal operations are coordinated with its Host BAs and TSP. This requirement relates to planned operations at a generator and does not include unplanned operations such as forced or emergency operations. The SDT recommends that this requirement be applied at the aggregate facility level for dispersed power producing resources. For example, forecasting available MW at the aggregated facility level is currently one method used. The SDT does not see any reliability gap in that would prompt this team to apply R3 to any point less than the dispersed power resource aggregated facility level.
The SDT has not found or been made aware of a reliability gap that would prompt this team to apply R3 to any point less than the dispersed power resource aggregated facility level and recommends such modification to the applicability of this requirement.

5.11.3.2 Requirement R13

The purpose of requirement R13 as it relates to GOPs is to ensure Real Power and Reactive Power capabilities are verified as requested by the BA and TOP. The SDT feels a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT is recommending that this requirement be applied at the aggregate facility level for dispersed power producing resources for the following reasons:

- Due to the nature, amount of individual generators at a dispersed power producing resource, internal Real Power losses, and natural inductance and capacitance of dispersed power resource system connected in series, verification of real and reactive capabilities should be conducted at the dispersed power producing resource aggregate facility level. Performing verification in this manner will provide an actual net real and reactive capability, which would be seen by both the BA and TOP. In addition, performing verification in this manner is also consistent with operating agreements such as an interconnection agreement, which the dispersed power resource has with the TOP and BA.
- MOD-025-2 also provides that verification for any generator <20MVA may be completed on an individual unit basis or as a "group." Reporting capability at the aggregated facility level is consistent with the MOD-025-2 provision for group verification.

[21] The GOP applicability is removed in TOP-002-3, which was adopted by the NERC BOT. However, TOP-002-3 was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

The SDT recommends a modification to the applicability of this requirement at the aggregated facility level for dispersed power producing resources.

5.11.3.3 Requirement R14

The purpose of requirement R14 as it relates to GOPs is to ensure BAs and TOPs are notified of changes in real output capabilities without any intentional time delay. It should be noted that the purpose of this requirement is to address unplanned changes in real output capabilities. It is assumed the required notification and coordination from the GOP to the BA and TOP would be done in real-time and through verbal communication media. The concern here is how to apply this to dispersed power producing resources. The SDT recommends that the GOP notify at the aggregate facility level to the TOP any unplanned changes in real output capabilities above 20 MVA. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition which includes generating units greater than 20MVA.
- TOP-002-2.1b R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the facility (e.g. 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.

Dispersed generation resources changes in real output capabilities should be reported as X MW out of Y MW are available. *The SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for unplanned outages greater than 20 MVA.*

5.11.3.4 Requirement R15

The purpose of requirement R15 as it relates to GOPs is to ensure BAs and TOPs are provided a forecast (e.g., seven day) of expected Real Power. The SDT believes this requirement as requested by the BA or TOP is being applied at the aggregate facility level for dispersed power producing resources.

Based on the SDT's experience, expected Real Power forecasts (e.g. 5 or 7 forecast) for a dispersed power producing resource has been traditionally coordinated with the BA and TOP at the aggregate facility level for dispersed power producing resources. *Therefore, the SDT recommends that R15 be applied at the aggregate facility level for dispersed power resources and as such, modification to the applicability of this requirement is necessary.*

5.11.3.5 Requirement R18

The purpose of requirement R18 as it relates to a GOP is to ensure uniform line identifiers are used when referring to transmission facilities of an interconnected network. The standard applies to transmission facilities of an interconnected network, which would not apply to any Elements within the dispersed generation facility. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

5.11.4 TOP-003-1— Planned Outage Coordination[22]

This TOP Standard has three requirements applied to GOPs. Modification to one of these requirements is recommended.

5.11.4.1 Requirement R1

The purpose of requirement R1 as it relates to GOPs is to ensure TOPs are provided planned outage information on a daily basis for any scheduled generator outage >50MW for the next day. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

5.11.4.2 Requirement R2

The purpose of requirement R2 as it relates to GOPs is to ensure all voltage regulating equipment scheduled outages are planned and coordinated with affected BAs and TOPs. A modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT recommends that this requirement be applied at the aggregate facility level for dispersed power producing resources.

Based on the SDT's experience, scheduled outages of voltage regulating equipment at a dispersed power producing resource has been traditionally provided to the BA and TOP at the aggregate facility level for dispersed power producing resources. Outages of voltage regulating equipment at a dispersed power producing resource are coordinated typically as a reduction in Reactive Power capabilities, specifying whether it is inductive, capacitive or both. Additionally, automatic voltage regulators that do not necessarily provide Reactive Power, but direct the actions of equipment that do supply Reactive Power, are typically coordinated at the aggregate facility level as they usually are the master controller for all voltage regulating equipment at the facility. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap, which would prompt this team to apply R2 to any point less than the dispersed power resource aggregated facility level and as in such, feels a modification to the applicability of this requirement is necessary for dispersed power producing resources.*

5.11.4.3 Requirement R3

The purpose of requirement R3 as it relates to GOPs is to ensure scheduled outages of telemetering and control equipment and associated communication channels are planned and coordinated among BAs and TOPs. Based on the SDT technical expertise, scheduled outages of telemetering and control equipment and associated communication channels at a dispersed power producing resource have been traditionally provided to the BA and TOP at the aggregate facility level for dispersed power producing resources. In addition, only scheduled outages of telemetering and control equipment and associated communication channels that can affect the BA and TOP are coordinated with the BA and TOP. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

5.11.5 TOP-006 — Monitoring System Conditions

The purpose of this standard as it relates to GOPs is to ensure BAs and TOPs know the status of all generation resources available for use as informed by the GOP. It should also be noted that the purpose

[22] Note that TOP-003-2, which is adopted by the NERC BOT, was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

of this standard is to ensure critical reliability parameters are monitored in real-time. It then can be extrapolated that the requirement, "GOP shall inform…," is done by sending dispersed power producing resource telemetry in real-time and through a digital communication medium, such as an ICCP link or RTU. The SDT feels a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT is recommending that this requirement be applied at the aggregate facility level for dispersed power producing resources for the following reasons:

- This is consistent with Inclusion I2 of the revised BES definition, which includes generating units greater than 20MVA. If removing <20MVA would cause a burden to the BPS, then the threshold for inclusion in the BES would have been less than 20MVA.
- Routine maintenance is frequently completed on a small portion of the entire facility (e.g. 2% of the generators are out of service on any given day) such as to not have a significant impact to the output capability of the facility. Additionally, it is not uncommon to have individual generating units at a dispersed power producing resource to go into a failure mode due to internal factors of the equipment, such as hydraulic fluid pressure tolerances, gearbox bearing thermal tolerances, etc. As such, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.
- As this standard requires real-time monitoring, this is most likely completed through a digital medium such as an ICCP link or RTU. The data that a dispersed power resource provides to the BA and TOP in real-time should include the aggregate active power output of the facility, among other telemetry points. These data specifications are usually outlined in interconnection agreements among the parties.

Based on the SDT technical expertise, BAs and TOPs are informed by the GOP of all generation resources available at the dispersed power producing resource at the aggregate facility level. Traditionally the dispersed power producing resources are providing the BA and TOP, at minimum, the following telemetry points in real-time: aggregate Real Power, aggregate Reactive Power and main high-side circuit breaker status. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap, which would prompt this team to apply these requirement to any point less than where the dispersed power resource aggregates and as in such, recommends a modification to the applicability of this requirement is necessary for dispersed power producing resources.*

5.12 TPL

These standards do not affect GOs or GOPs directly. Input from GO or GOP entities is provided to transmission planning entities through the MOD standards. *Therefore, the applicability of the TPL standards does not need to be changed for dispersed generation resources.*

5.13 VAR

The VAR standards exist to ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained. There are two VAR Standards that apply to GOs and/or GOPs. The voltage and/or reactive schedule provided by TOPs is specified to be at the point of interconnection or the point specified in the interconnection agreement.

5.13.1 VAR-001 — Voltage and Reactive Control (WECC Regional Variance)

The purpose of this standard as it relates to GOPs in WECC is to ensure a generator voltage schedule is issued that is appropriate for the type of generator(s) at a specific facility. Additionally, it requires GOPs to have a methodology for how the voltage schedule is met taking into account the type of equipment used to maintain the voltage schedule. Based on the SDT technical expertise, voltage control and voltage schedule adherence for dispersed power producing resource occurs at the aggregate facility level. There is no need to differentiate dispersed generation resources from any other GOP resources. *Therefore, the applicability of VAR-001 does not need to be changed for dispersed generation resources.*

5.13.2 VAR-002-2b — Generator Operation for Maintaining Network Voltage Schedules

The purpose of this standard as it relates to GOs and GOPs is to ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and reliability of the Interconnection. Based on the SDT technical expertise, voltage control and voltage schedule adherence for dispersed power producing resource occurs at the aggregate facility level. In addition, dispersed power producing resources individual generator transformers have traditionally been excluded from the R4 and R5, as they are not used to improve voltage performance at the point of interconnection. *Therefore, the SDT recommends clarifying the applicability of VAR-002 for dispersed generation resources.*

5.14 CIP

5.14.1 CIP v5

The CIP standards ensure physical and cyber security for BES Cyber Assets and BES Cyber Systems critical to the reliability and security of the BES. CIP-002 identifies critical assets or systems of a facility, while CIP-003 to CIP-011 depend on the outcome of the CIP-002 assessment to determine applicability.

The SDT states that the CIP Version 5 Revisions SDT should consider developing guidance documentation around the following areas:

- Low Impact BES Cyber Systems that must comply with a limited number of requirements, all located in CIP-003-5. The only technical requirement is R2, which will be modified during the current drafting activity to add clarity to the requirement. The SDT notes that the CIP Version 5 Revisions SDT should consider developing guidance around how this requirement relates to dispersed generation.
- Any programmable logic device that has the capability to shut down the plant within 15 minutes; and
- Remote access from third party entities into the SCADA systems that control the aggregate capacity of a facility should be assessed to determine if there is a need of any additional cyber security policies.

NERC staff has committed to facilitate communication between the SDT and the CIP Version 5 Revisions SDT as appropriate to ensure alignment. *Therefore, the applicability of CIP standards does not need to be changed for dispersed generation resources.*

6 Appendix A: List of Standards

7 Appendix B: List of Standards Recommended for Further Review

Standard Number	Subject to Enforcement	Further Review by SDT	Regional
BAL-001-1	Subject to Enforcement	No	
BAL-001-TRE-1	Subject to Enforcement	Yes	YES
BAL-002-1	Subject to Enforcement	No	
BAL-STD-002-0	Subject to Enforcement	No	YES
BAL-002-WECC-02	Subject to Enforcement	No	YES
BAL-003-0.1b	Subject to Enforcement	No	
BAL-004-0	Subject to Enforcement	No	
BAL-004-WECC-02	Subject to Enforcement	No	YES
BAL-005-0.2b	Subject to Enforcement	No	
BAL-006-2	Subject to Enforcement	No	
BAL-502-RFC-02	Subject to Enforcement	No	YES
CIP-002-3	Subject to Enforcement	No	
CIP-003-3	Subject to Enforcement	No	
CIP-004-3a	Subject to Enforcement	No	
CIP-005-3a	Subject to Enforcement	No	
CIP-006-3c	Subject to Enforcement	No	
CIP-007-3a	Subject to Enforcement	No	
CIP-008-3	Subject to Enforcement	No	
CIP-009-3	Subject to Enforcement	No	
COM-001-1.1	Subject to Enforcement	No	
COM-002-2	Subject to Enforcement	No	
EOP-001-2.1b	Subject to Enforcement	No	
EOP-002-3.1	Subject to Enforcement	No	
EOP-003-2	Subject to Enforcement	No	
EOP-004-2	Subject to Enforcement	No	
EOP-005-2	Subject to Enforcement	No	
EOP-006-2	Subject to Enforcement	No	
EOP-008-1	Subject to Enforcement	No	
FAC-001-1	Subject to Enforcement	No	
FAC-002-1	Subject to Enforcement	No	
FAC-003-1	Subject to Enforcement	No	
FAC-008-3	Subject to Enforcement	Yes	
FAC-010-2.1	Subject to Enforcement	No	
FAC-011-2	Subject to Enforcement	No	
FAC-013-2	Subject to Enforcement	No	
FAC-014-2	Subject to Enforcement	No	
FAC-501-WECC-1	Subject to Enforcement	No	YES
INT-001-3	Subject to Enforcement	No	
INT-003-3	Subject to Enforcement	No	
INT-004-2	Subject to Enforcement	No	
INT-005-3	Subject to Enforcement	No	
INT-006-3	Subject to Enforcement	No	
INT-007-1	Subject to Enforcement	No	
INT-008-3	Subject to Enforcement	No	
INT-009-1	Subject to Enforcement	No	
INT-010-1	Subject to Enforcement	No	
IRO-001-1.1	Subject to Enforcement	No	
IRO-002-2	Subject to Enforcement	No	
IRO-003-2	Subject to Enforcement	No	
IRO-004-2	Subject to Enforcement	No	
IRO-005-3.1a	Subject to Enforcement	No	
IRO-006-5	Subject to Enforcement	No	
IRO-006-EAST-1	Subject to Enforcement	No	YES
IRO-006-TRE-1	Subject to Enforcement	No	YES

IRO-006-WECC-1	Subject to Enforcement	No	YES
IRO-008-1	Subject to Enforcement	No	
IRO-009-1	Subject to Enforcement	No	
IRO-010-1a	Subject to Enforcement	No	
IRO-014-1	Subject to Enforcement	No	
IRO-015-1	Subject to Enforcement	No	
IRO-016-1	Subject to Enforcement	No	
MOD-001-1a	Subject to Enforcement	No	
MOD-004-1	Subject to Enforcement	No	
MOD-008-1	Subject to Enforcement	No	
MOD-010-0	Subject to Enforcement	No	
MOD-012-0	Subject to Enforcement	No	
MOD-016-1.1	Subject to Enforcement	No	
MOD-017-0.1	Subject to Enforcement	No	
MOD-018-0	Subject to Enforcement	No	
MOD-019-0.1	Subject to Enforcement	No	
MOD-020-0	Subject to Enforcement	No	
MOD-021-1	Subject to Enforcement	No	
MOD-028-2	Subject to Enforcement	No	
MOD-029-1a	Subject to Enforcement	No	
MOD-030-2	Subject to Enforcement	No	
NUC-001-2.1	Subject to Enforcement	No	
PER-001-0.2	Subject to Enforcement	No	
PER-003-1	Subject to Enforcement	No	
PER-004-2	Subject to Enforcement	No	
PER-005-1	Subject to Enforcement	No	
PRC-001-1.1	Subject to Enforcement	Yes	
PRC-002-NPCC-01	Subject to Enforcement	No	YES
PRC-004-2.1a	Subject to Enforcement	Yes	
PRC-004-WECC-1	Subject to Enforcement	Yes	YES
PRC-005-1.1b	Subject to Enforcement	Yes	
PRC-006-1	Subject to Enforcement	No	
PRC-006-SERC-01	Subject to Enforcement	Yes	YES
PRC-008-0	Subject to Enforcement	No	
PRC-010-0	Subject to Enforcement	No	
PRC-011-0	Subject to Enforcement	No	
PRC-015-0	Subject to Enforcement	No	
PRC-016-0.1	Subject to Enforcement	No	
PRC-017-0	Subject to Enforcement	No	
PRC-018-1	Subject to Enforcement	No	
PRC-021-1	Subject to Enforcement	No	
PRC-022-1	Subject to Enforcement	No	
PRC-023-2	Subject to Enforcement	No	
TOP-001-1a	Subject to Enforcement	Yes	
TOP-002-2.1b	Subject to Enforcement	Yes	
TOP-003-1	Subject to Enforcement	Yes	
TOP-004-2	Subject to Enforcement	No	
TOP-005-2a	Subject to Enforcement	No	
TOP-006-2	Subject to Enforcement	Yes	
TOP-007-0	Subject to Enforcement	No	
TOP-007-WECC-1	Subject to Enforcement	No	YES
TOP-008-1	Subject to Enforcement	No	
TPL-001-0.1	Subject to Enforcement	No	
TPL-002-0b	Subject to Enforcement	No	
TPL-003-0b	Subject to Enforcement	No	

TPL-004-0a	Subject to Enforcement	No	
VAR-001-3	Subject to Enforcement	No	
VAR-001-3 (WECC)	Subject to Enforcement	No	YES
VAR-002-2b	Subject to Enforcement	Yes	
VAR-002-WECC-1	Subject to Enforcement	No	YES
VAR-501-WECC-1	Subject to Enforcement	No	YES
Standard Number	Subject to Future Enforcement	Further Review by SDT	
BAL-003-1	Subject to Future Enforcement	No	
CIP-002-5.1	Subject to Future Enforcement	No	
CIP-003-5	Subject to Future Enforcement	No	
CIP-004-5.1	Subject to Future Enforcement	No	
CIP-005-5	Subject to Future Enforcement	No	
CIP-006-5	Subject to Future Enforcement	No	
CIP-007-5	Subject to Future Enforcement	No	
CIP-008-5	Subject to Future Enforcement	No	
CIP-009-5	Subject to Future Enforcement	No	
CIP-010-1	Subject to Future Enforcement	No	
CIP-011-1	Subject to Future Enforcement	No	
FAC-003-3	Subject to Future Enforcement	No	
PRC-005-2	Subject to Future Enforcement	Yes	
PRC-006-NPCC-1	Subject to Future Enforcement	Yes	YES
TPL-001-4	Subject to Future Enforcement	No	
MOD-025-2	Subject to Future Enforcement	Yes	
MOD-026-1	Subject to Future Enforcement	Yes	
MOD-027-1	Subject to Future Enforcement	Yes	
PRC-019-1	Subject to Future Enforcement	Yes	
PRC-024-1	Subject to Future Enforcement	Yes	
Standard Number	Pending Regulatory Approval	Further Review by SDT	
BAL-002-1a	Pending Regulatory Approval	No	
EOP-010-1	Pending Regulatory Approval	No	
INT-004-3	Pending Regulatory Approval	No	
INT-006-4	Pending Regulatory Approval	No	
INT-009-2	Pending Regulatory Approval	No	
INT-010-2	Pending Regulatory Approval	No	
INT-011-1	Pending Regulatory Approval	No	
IRO-002-3	Pending Regulatory Approval	No	
IRO-006-WECC-2	Pending Regulatory Approval	No	YES
IRO-014-2	Pending Regulatory Approval	No	
MOD-001-2	Pending Regulatory Approval	No	
MOD-011-0	Pending Regulatory Approval	No	
MOD-013-1	Pending Regulatory Approval	No	
MOD-014-0	Pending Regulatory Approval	No	
MOD-015-0	Pending Regulatory Approval	No	
MOD-032-1	Pending Regulatory Approval	Yes	
MOD-033-1	Pending Regulatory Approval	No	
PER-005-2	Pending Regulatory Approval	No	
PRC-001-2	Pending Regulatory Approval	No	
PRC-002-1	Pending Regulatory Approval	No	
PRC-003-1	Pending Regulatory Approval	No	
PRC-005-3	Pending Regulatory Approval	Yes	
PRC-012-0	Pending Regulatory Approval	No	
PRC-013-0	Pending Regulatory Approval	No	
PRC-014-0	Pending Regulatory Approval	No	
PRC-020-1	Pending Regulatory Approval	No	
PRC-023-3	Pending Regulatory Approval	No	

PRC-025-1	Pending Regulatory Approval	Yes	
TOP-001-2	Pending Regulatory Approval	Yes	
TOP-006-3	Pending Regulatory Approval	Yes	
TOP-007-WECC-1a	Pending Regulatory Approval	No	YES
Standard Number	Pending Regulatory Filing	Further Review by SDT	
BAL-001-2	Pending Regulatory Filing	No	
CIP-002-3b	Pending Regulatory Filing	No	
CIP-003-3a	Pending Regulatory Filing	No	
CIP-007-3b	Pending Regulatory Filing	No	
COM-001-2	Pending Regulatory Filing	No	
COM-002-2a	Pending Regulatory Filing	No	
COM-002-3	Pending Regulatory Filing	No	
MOD-015-0.1	Pending Regulatory Filing	No	
VAR-001-4	Pending Regulatory Filing	No	
Standard Number	Designated for Retirement	Further Review by SDT	
MOD-024-1	Designated for Retirement	No	
MOD-025-1	Designated for Retirement	No	
Standard Number	Proposed for Remand	Further Review by SDT	
IRO-001-3	Proposed for Remand	No	
IRO-005-4	Proposed for Remand	No	
TOP-002-3	Proposed for Remand	No	
TOP-003-2	Proposed for Remand	No	

Standard Number	Subject to Enforcement	Further Review by SDT
Standard Number	Subject to Future Enforcement	Further Review by SDT
Standard Number	Pending Regulatory Approval	Further Review by SDT
Standard Number	Pending Regulatory Filing	Further Review by SDT
Standard Number	FERC Designated for Retirement	Further Review by SDT
Standard Number	FERC - Remand	Further Review by SDT

HIGH PRIORITY			
Standard Number	Status	Area To Change	Target Applicability
PRC-004-2.1a	FERC Approved - Subject to Enforcement	Applicability Section	Point where aggregates to >75MVA
PRC-005-1.1b	FERC Approved - Subject to Enforcement	Applicability Section	Point where aggregates to >75MVA
PRC-005-2	FERC Approved - Subject to Future Enforcement	Applicability Section	Point where aggregates to >75MVA
VAR-002-2b	FERC Approved - Subject to Enforcement	Applicability Section	Point where aggregates to >75MVA
PRC-005-3	NERC BOT Adopted - Pending Regulatory Approval	Applicability Section	Point where aggregates to >75MVA
MEDIUM PRIORITY			
Standard Number	Status	Area To Change	Target Applicability
FAC-008-3	FERC Approved - Subject to Enforcement	Guidance	Individual BES Resources/Elements
PRC-001-1.1	FERC Approved - Subject to Enforcement	By Requirement	Aggregate Facility Level
PRC-019-1	FERC Approved - Subject to Future Enforcement	Guidance	Point of common control
PRC-024-1	FERC Approved - Subject to Future Enforcement	Guidance	Individual BES Resources/Elements
PRC-025-1	NERC BOT Adopted - Pending Regulatory Approval	Guidance	Individual BES Resources/Elements
TOP-001-1a	FERC Approved - Subject to Enforcement	By Requirement	Aggregate Facility Level
TOP-001-2	NERC BOT Adopted - Pending Regulatory Approval	By Requirement	Aggregate Facility Level
TOP-002-2.1b	FERC Approved - Subject to Enforcement	Applicability Section	Aggregate Facility Level
TOP-003-1	FERC Approved - Subject to Enforcement	By Requirement	Aggregate Facility Level
TOP-006-2	FERC Approved - Subject to Enforcement	Applicability Section	Aggregate Facility Level
TOP-006-3	NERC BOT Adopted - Pending Regulatory Approval	Applicability Section	Aggregate Facility Level
MOD-025-2	FERC Approved - Subject to Future Enforcement	Guidance	Point of common control
MOD-026-1	FERC Approved - Subject to Future Enforcement	Applicability Section	Point of common control
MOD-027-1	FERC Approved - Subject to Future Enforcement	Applicability Section	Point of common control
MOD-032-1	NERC BOT Adopted - Pending Regulatory Approval	Guidance	Individual BES Resources/Elements
LOW PRIORITY			
Standard Number	Status	Area To Change	Target Applicability
BAL-001-TRE-1	FERC Approved - Subject to Enforcement	Applicability Section	Aggregate Facility Level
PRC-004-WECC-1	FERC Approved - Subject to Enforcement	Applicability Section	Point where aggregates to >75MVA
PRC-006-NPCC-1	FERC Approved - Subject to Future Enforcement	By Requirement	Individual BES Resources/Elements
PRC-006-SERC-01	FERC Approved - Subject to Enforcement	By Requirement	Individual BES Resources/Elements

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the posted documents. The electronic comment form must be completed by **May 5, 2014.**

If you have questions please contact Sean Cavote or by telephone at 404-446-9697.

All documents for this project are available on the project page.

Background Information

This posting solicits informal comments on the preliminary recommendations of the Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) standards drafting team (SDT). The DGR SDT has posted a draft white paper to provide background and technical rationale for proposed revisions to the applicability of several Reliability Standards, along with a Standards Authorization Request (SAR) Draft 2 and the DGR SDT's response to comments on the original SAR for this project.

As explained in the white paper, the goal of the DGR SDT is to ensure that Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System (BPS), as the characteristics of operating dispersed power producing resources can be unique. In light of the revised BES definition approved by the Federal Energy Regulatory Authority (FERC) in 2014, the intent of this effort is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources, where the status quo does not create a reliability gap, and to ensure continent-wide consistency in the application of reliability standards to dispersed power producing resources.

The DGR SDT performed a review of all standards that apply to GOs and GOPs (listed in Appendix A, as posted) and determined how each standard requirement should be appropriately applied to dispersed power producing resources, which are categorized as follows:

- The existing standard language is appropriate when applied to dispersed generating resources and does not need to be addressed;
- The existing standard language is appropriate when applied to dispersed generating resources but additional NERC guidance documentation is needed to clarify either how to implement the requirements for dispersed generating resources or how to demonstrate compliance for such resources; and

- The existing standard language needs to be modified in order to account for the unique characteristics of dispersed generation resources. This could be accomplished through the applicability section of the standard in most cases or, if required, through changes to the individual requirements. However, please note that any recommended changes to requirements are limited to changes in the applicability of the subject requirement and will not include technical changes to any requirement.

From this review the SDT determined that there are three high priority standards in which immediate attention is required to provide direction to industry stakeholders as soon as feasible regarding how to appropriately direct compliance related preparations:

- PRC-004-2.1a;
- PRC-005 (versions -2, -3, and the version currently in development in Project 2007-17.3) ; and
- VAR-002.

However, the SDT has recognized that other standards (listed in posted Appendix B) may require further review by the SDT to determine the necessity and the type of clarification or guidance to the applicability for dispersed power producing resources. This necessity is based on how each standard requirement, as written, would apply to dispersed generation resources and the individual generating units at these facilities, considering the recently approved BES definition. The proposed resolutions could target the applicability language in the applicability section or in individual requirements. There may be other methods to ensure consistent throughout the Regions, including modifying Reliability Standard Audit Worksheet (RSAW) language or having guidance issued by NERC. These tools, among others, will be considered by the SDT throughout the project.

This posting includes three documents:

- Draft White Paper;
- Appendix A – List of all standards reviewed by the DGR SDT
- Appendix B – List of standards recommended as requiring further consideration for dispersed power-producing resources

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. The posted white paper and its Appendix B identify 24 standards that may require modifications or guidance to account for the unique characteristics of dispersed power producing resources, including three high priority standards. Do you agree that the DGR SDT has correctly identified the standards that require applicability changes or additional guidance for dispersed power producing resources? If not, please explain.

   ☐ Yes
   ☐ No

   Comments:

2. The posted white paper and its Appendix B describe how the SDT recommends addressing dispersed power producing resources through changes to the applicability section, guidance documentation, or in the applicability of requirements. Do you agree that the DGR SDT has correctly identified the best approach for each standard? If not, please explain.

   ☐ Yes
   ☐ No

   Comments:

3. The posted white paper and its Appendix B identify six standards where guidance may be sufficient to account for the unique characteristics of dispersed power producing resources. Such guidance may include recognition of aggregating common components as a single "Element" for Facility Ratings and using aggregated capacity value, not individualized units, in the modeling needs. Do you agree that the DGR SDT has correctly identified standards for which applicability changes are not needed, but guidance to clarify application of the standard to dispersed power producing resources would be helpful? If not, please explain.

   ☐ Yes
   ☐ No

   Comments:

4. Section 4.3.3 of the posted white paper describes the prioritization methodology the DGR SDT used to assign high, medium, or low priority to its review of each standard's applicability in the context of dispersed power producing resources, and Appendix B contains the results of that prioritization. Has the DGR SDT appropriately prioritized the standards? If not, please explain.

   ☐ Yes
   ☐ No

   Comments:

The next series of questions seek feedback on the technical section of the white paper (section 5).

5. In section 5.10.4 the DGR SDT recommends changing the applicability of PRC-004-2.1a. Has the DGR SDT provided adequate justification or rationale to support revising the applicability of PRC-004-2.1a? If not, please either provide additional reliability-based justification or explain what is needed.

   ☐ Yes
   ☐ No

   Comments:

6. The DGR SDT believes it is not necessary under PRC-004 to analyze protection system misoperations affecting individual dispersed generating units, but is concerned with the potential for unreported misoperations involving a common mode trip of several generating units. The DGR SDT proposes requiring analysis for potential misoperation of individual generating units, if a trip of greater than 75 MVA aggregate occurs in response to a system disturbance. Do you agree with this approach? If not, please provide specific examples or rationale to support an alternate approach.

   ☐ Yes
   ☐ No

   Comments:

7. In section 5.10.6 the DGR SDT recommends making several changes to tailor the applicability of PRC-005 for dispersed power-producing resources. Has the DGR SDT provided adequate justification or rationale to support revising the applicability of PRC-005? If not, please either provide additional reliability-based justification or explain what is needed.

   ☐ Yes
   ☐ No

   Comments:

8. With respect to the PRC standards, do you believe a common mode failure which results in misoperation of a large number of the individual generating resources at a dispersed generation resource site may impact BES reliability? Please explain your answer.

   ☐ Yes
   ☐ No

   Comments:

9. In section 5.13.2 of the white paper, has the DGR SDT provided adequate justification or rationale to support revising the applicability of VAR-002-2b? If not, please either provide additional reliability-based justification or explain what is needed.

   ☐ Yes
   ☐ No

   Comments:

10. With respect to VAR-002-2b, does the NERC DGR SDT need to provide guidance to ensure dispersed power producing resources individual generator transformers are subject to the R4 and R5, as they are not used to improve voltage performance at the point of interconnection?

   ☐ Yes
   ☐ No

   Comments:

11. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

☐ Yes
☐ No

Comments:

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources

White Paper Informal Comment Period Now Open through May 5, 2014

Now Available

An informal comment period for the Project 2014-01 Standards Applicability for Dispersed Generation Resources White Paper is now open through **8 p.m. Eastern on Monday, May 5, 2014.**

The white paper is intended to provide technical rationale and justification to support identification of standards that will require modifications to applicability for the unique characteristics of dispersed power producing resources as identified under Inclusion I4 of the BES definition that becomes effective on July 1, 2014.   Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

The drafting team will review stakeholder comments and develop modifications for those standards for which modified applicability for dispersed generation resources is justified and supports reliability. In cases where applicability changes are developed for standards that are being modified in another standard development projects, the applicability changes will be coordinated with the drafting team making the technical changes, but will be balloted separately and filed for regulatory approval in a separate petition.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower

Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (24 Responses)
Name (12 Responses)
Organization (12 Responses)
Group Name (12 Responses)
Lead Contact (12 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (0 Responses)
Comments (24 Responses)
Question 1 (22 Responses)
Question 1 Comments (24 Responses)
Question 2 (21 Responses)
Question 2 Comments (24 Responses)
Question 3 (17 Responses)
Question 3 Comments (24 Responses)
Question 4 (17 Responses)
Question 4 Comments (24 Responses)
Question 5 (20 Responses)
Question 5 Comments (24 Responses)
Question 6 (22 Responses)
Question 6 Comments (24 Responses)
Question 7 (20 Responses)
Question 7 Comments (24 Responses)
Question 8 (21 Responses)
Question 8 Comments (24 Responses)
Question 9 (16 Responses)
Question 9 Comments (24 Responses)
Question 10 (16 Responses)
Question 10 Comments (24 Responses)
Question 11 (22 Responses)
Question 11 Comments (24 Responses)

Group
Dominion NERC Compliance Policy
Randi Heise
No
Dominion does not agree from a technical perspective. The requirement applies to all entities registered as GOP. There is no defined reporting threshold in the standard. We think the recently filed (but remanded TOP standards) allowed the TOP to determine its data reporting requirements; and, Dominion knows for a fact that PJM requires its intermittent resources to report any change to real power that is equal to, or exceeds, 1 mw. For this reason, we do not

agree with the SDT relative to this requirement. Also disagree with 5.11.3.3 Requirement R14 for same reason.
Yes
No
See preceding comments.
Yes
Dominion agrees with the prioritization methodology as well as the priority assigned to each stanadard. However, Dominion does not agree with the Target Applicability assigned to some of the TOP standards (see previous comment) and suggests the SDT be consistent in verbiage used or explain if there is a reason for the differences. Examples are: Point where aggregates to >75MVA and Aggregate Facility Level.
Yes
Dominion agrees with the SDT that the Misoperations of any individual generating unit may not have an impact upon the BPS and agrees that it is not necessary to analyze Protective System Misoperations affecting individual generation units of dispersed generation resources. Dominion further supports the analysis of potential Misoperations of dispersed generation resources if the trip is greater than 75 MVA of aggregate occurs in response to a system disturbance. Dominion supports the continued review and study of the potential reporting process for Misoperations required by dispersed generation resources due to the limited information available due to turbine design and technology that would be available for analysis and reporting.
Yes
Yes
Yes
Dominion believes that a misoperation that results in the loss of dispersed power generation for resources greater than 74MV may have a significant impact on BES reliability. We thefore support a threshold of 75 MVA for such resources under this standard.
No
We do not support a blanket exclusion of dispersed power producing resources from requirements 4 & 5. If such respurces have been traditionally excluded then we would expect their respective TO and TP to continue such exclusion, if they so choose.
No
No
Group
PacifiCorp

Sandra Shaffer
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
The SDT recognizes concern with the potential for reliability impacts involving a common mode failure that leads to (1) loss of a significant number of generating units or the entire facility (White Paper Section 4.2.3 – Page 8) or (2) the potential for misoperations involving several individual generating units (5.10.4 – Page 19). PacifCorp shares this concern. The reliability impacts of a common mode failure and related loss of units at a dispersed generation resource site may affect reliability depending upon the magnitude, timing, and duration of the resource loss. PacifiCorp agrees with the SDT proposal of requiring analysis for potential Misoperation of individual generating units, if a trip of greater than 75 MVA aggregate occurs in response to a system disturbance.
Yes
Yes
PacifiCorp agrees that dispersed power producing resource individual generator transformers have traditionally been excluded from VAR-002-2b R4 and R5, as they are not used to improve voltage performance at the point of interconnection, and further agrees with the SDT on the need to clarify the applicability of VAR-002-2b to exclude dispersed power producing resource individual generator transformers from R4 and R5 up to the point of aggregation of 75 MVA, as they are not used to improve voltage performance at the point of interconnection.
Yes
As discussed in White Paper Sections 5.10.11 and 5.10.12 (applicable to PRC-024 and PRC-025), PacifiCorp supports the point made by the SDT, that for the purpose of compliance evidence it may be sufficient to provide the settings of a single sample unit within a site as

these units are typically set identically, rather than providing documentation for each individual unit.
Group
Northeast Power Coordinating Council
Guy Zito
No
PRC-004-2.1a should not be modified to exclude dispersed power producing resources. it is important to know about relay misoperations in order to maintain system reliability. This extends to individual units that make up an aggregated dispersed power producing resource, especially when one considers the potential that similar practices would be used in setting each of the protection systems applied to individual units . FERC has explicitly recognized this in its March 20, 2014 Order Approving Revised Definition, where it stated that: “[f]or example, a wind farm larger than 75 MVA can affect reliability if all of its wind turbines trip offline simultaneously after just a slight fluctuation in voltage or frequency. Therefore, because variable generation can impact the interconnected transmission network, we anticipate that wind plant owners whose facilities meet the inclusion I4 criteria who seek to exclude individual wind turbines from the bulk electric system through the exception process will be infrequent.” See North American Reliability Corporation, 146 FERC ¶ 61,199 (2014) at P 48.
No
The applicability of PRC-004 should not be modified as explained above in the response to Question No. 1.
Yes
With respect to MOD-032, it is important that generators provide accurate models of each individual unit. Therefore, if all units are identical, then providing aggregate information may be sufficient. However, if units are not identical, then generators should be required to provide individual models.
No
PRC-004 and associated relay misoperations are important for reliability. Efforts to reduce it’s applicability should not be a priority.
No
The justification provided by the SDT is contrary to FERC’s March 20, 2014 Order (please refer to the response to Question No. 1 above).
No
We do not agree with this approach because limiting the analysis requirement to a trip of greater than 75 MVA only accounts for very large occurrences that could be unusual. Smaller occurrences, however, may predict an unusual large occurrence that could impact reliability especially when one considers the potential that similar practices would be used in setting each of the protection systems applied to individual units.
No

In general, relay maintenance is a vital part of system reliability and reducing the applicability of the standard seems counter to good utility practice.
Yes
Yes, as explicitly recognized by FERC, a wind farm larger than 75 MVA can affect reliability if all of its wind turbines trip offline simultaneously after just a slight fluctuation in voltage or frequency. In addition, loss of a wind farm as a dispersed generation resource has been observed real time to impact Quebec's Main Transmission System (the Quebec equivalent of the BES). In Quebec, all the generation or dispersed generation greater than 50MVA connected into 44kV and above are included in its Main Transmission System. Because of the variability of system loads (peak, off-peak, shoulder periods), and the electrical locations of generating resources and their impacts on the BES, what is a large number of generating resources?
No
In general, providing voltage regulation at the point of aggregation is acceptable. However embedded dynamic devices may affect aggregate voltage performance. The "clarification" needs to address this.
No
There is no need to modify the applicability of R4 and R5 of VAR-002-2b. The information under R4 has to be provided only upon request of the Transmission Planner and Transmission Operator. If this information is not necessary, it should not be requested and, accordingly, there is no need to modify the standard. Similarly, R5 is only applicable if the Transmission Operator requests a change to the tap setting. The Transmission Operator should only do this when necessary; therefore, there is no need to modify the applicability of the standard. In addition, other reactive devices, such as embedded dynamic reactive devices,may affect aggregate voltage performance and should be addressed.
No
Individual
John Seelke
Public Service Enterprise Group
No
Although Inclusion I4 refers to dispersed power resources that are "greater than 75 MVA to a common point of connection at a voltage of 100 kV or above," for comparability to traditional resources (Inclusion I2), changes in standard thresholds for dispersed resources should apply to points where dispersed resources aggregate to greater than 20 MVA at a common point. While these points may be considered non-BES, many standards apply to non-BES Elements, and the BES definition does not prohibit the application of standards to non-BES Elements. For example, Cranking Paths that are less than 100 kV are still subject to EOP-005-2. See Order 773, paragraph 103. In addition UFLS is not in the BES definition, but standards still apply – see PRC-006-2. • We note that the team has taken this approach on p. 25 with respect

to TOP-002-2.1b, R14. However, Appendix B recommends a threshold at the “Point where [generation] aggregates to >75MVA” for the five “High Priority” standards. Appendix B tracks the recommends in the white paper where each standard is discussed, with the exception of VAR-002 – there is no mention of “Point where [generation] aggregates to >75MVA” and neither should there be. We urge the team to reconsider and adopt a consistent “point where generation aggregates to > 20 MVA” approach in each of these standards (except VAR-002). If a 20 MVA threshold applies to I2 generators and that’s reliability-based, there would be a reliability gap if a > 75 MVA threshold was adopted.
Yes
Yes, with respect as to “what” changes need to be addressed. However, the white paper is unclear as to “how” it will attempt to implement those changes (i.e., the process it will follow). A new column should be added to Appendix B that addresses the “how.” Here are examples of potential implementation problems that the team should consider: PRC-004-2.1a (Misoperations) is undergoing revisions to PRC-004-3 in Project 2010-05.1 Protection Systems - Phase 1 (Misoperations). How will the team address its needed changes, given that ongoing project? • The same applies to changes in PRC-005 – a team is developing PRC-005-4 in Project 2007-17.3 Phase 3 of Protection System Maintenance and Testing (Sudden Pressure Relays) • And same applies to changes in VAR-002 – a team has just completed a passing successive ballot on VAR-002-3 in Project 2013-04 Voltage & Reactive Control The question on “how” is administrative, but extremely important. If an existing SDT is working on a standard and a second SDT wants to work on that same standard, but with a different scope, it would be very inefficient to have two teams balloting different versions of the same standard, which must eventually be combined. Only ONE team should be involved in changing a standard at a time. To do that, the existing team’s SAR (which is its scope) would need to be amended to include the additional scope of the second SDT. I don’t believe the SDT has considered this issue.
Yes
No
As stated and supported in response to question 1, we believe the aggregate threshold should be > 20 MVA, not > 75 MVA. If a 20 MVA threshold applies to I2 generators and that’s reliability-based, there would be a reliability gap if a > 75 MVA threshold was adopted.
No
As stated and supported in response to question 1, we believe the aggregate threshold should be > 20 MVA, not > 75 MVA. If a 20 MVA threshold applies to I2 generators and that’s reliability-based, there would be a reliability gap if a > 75 MVA threshold was adopted.
No
As stated and supported in response to question 1, we believe the aggregate threshold should be > 20 MVA, not > 75 MVA. If a 20 MVA threshold applies to I2 generators and that’s reliability-based, there would be a reliability gap if a > 75 MVA threshold was adopted.

Yes
A common mode failure could be caused by either a consistently applied bad relay setting (more likely) or consistently bad relays (less likely).
Individual
Thomas Foltz
American Electric Power
Yes
AEP supports the efforts of this drafting team, and believes that the approach proposed in the white paper is reasonable (including the importance of focusing on PRC-004, PRC-005, and VAR-002). AEP will review the additional standards that the drafting team believes are and are-not impacted, and will provide comments on those in future comment periods.
Group
MRO NERC Standards Review Forum
Joe DePoorter
No
Within Appendix B under column “Target Applicability” there are four (4) different applications; “Point where aggregates to > 75 MVA, Individual BES Resources / Elements, Point of common control, and Aggregate Facility Level. Without these attributes being defined, the industry cannot know if the Standards within Appendix B have the proper “Target Applicability”. Recommend that these terms be included in the NERC Glossary of Terms as they will have a major impact on the applicability of the Standards with reference to dispersed power producing resources. The SDT is encouraged to proceed expeditiously on the identified high priority standards: PRC-004-2.1a, PRC-005 (relevant versions) and VAR-002 so

that owners can proceed with implementation of the BES definition and these standards without unnecessary interim work.
Yes
Yes this seems reasonable.
No
The SDT has not made in clear what six (6) Standards they are referring too. Within in Appendix B, there are six (6) standards with the Target Applicability of either "Point where aggregates to > 75 MVA" or "Individual BES Resources / Elements". Which six (6) Standards is the SDT referring to?
No
The NSRF does not understand why the High priority states: "High priority was assigned if compliance-related efforts with no appreciable reliability benefit would require not only significant resources but also would require efforts to be initiated by anentity well in advance of the implementation date". The NSRF believes that High Priority should have a the STRONGEST reliability benefit, not "…with no appreciable reliability benefit…". The NSRF does agree with the High, Medium and Low priority prioritization methodology.
Yes
The NSRF agrees and would like to have the wording in the applicability statement that PRC-004-2.1a will only be implemented when there is a trip greater the or equal to 75 MVA, or words to that effect.
Yes
The NSRF agrees and would like to have the wording in the applicability statement that PRC-004-2.1a will only be implemented when there is a trip greater the or equal to 75 MVA, or words to that effect.
Yes
Yes
Yes, and recommend that the 75 MVA threshold be used as in PRC-004.
No
Section 5.13.2 uses the words of "aggregate facility level". The NSRF recommends that Facility use a capitol F. This term is used like the Target Applicability which is not defined. Within Appendix B under column "Target Applicability" there are four (4) different applications; "Point where aggregates to > 75 MVA, Individual BES Resources / Elements, Point of common control, and Aggregate Facility Level. Without these attributes being defined, the industry cannot know if the Standards within Appendix B have the proper "Target Applicability".
Yes
The SDT needs to provide less guidance whereby the GO/GOP can develop their own way of meeting the TOP's voltage schedule. The SDT should not be so granular to discuss items that are on the collector system, which is not a BES asset.
Yes

Section 4.2.2, First paragraph, Please note that just because technology exist in short term forecasting capabilities, there are small entities that may not have these expensive tools. There may have been State Laws that mandated the use of dispersed power producing resources within their capacity portfolios. Recommend section 4.2.2, be updated to read that technology exist but may not be employeed by entity’s with dispersed power producing resources. Section 4.2.2, Second paragraph, as stated above, the same is true for concerning voltage and frequency system support. The majority of dispersed power producing resources provide real power and voltage which is provided by a fixed power factor control. The SDT’s White Paper needs to take in many system configurations, we are not all created equal. Please note that the NSRF cannot comment on the Priority of Standards listed in appendix B since the Target Applicability terms are not defined.
Individual
Amy Casuscelli
Xcel Energy
Yes
No
We strongly disagree with the assertion that issues with FAC-008-3 can be addressed with guidance alone. We agree with the SAR recommendations that the applicability of FAC-008 be limited to the point of 75 MVA or above. Furthermore, we think the wording of requirements R1 and R2 is very problematic due to the uncertainty caused by the usage of the term "main step up transformer" as well as the wide variability in the possible location of "the point of interconnection with the Transmission Owner." For example, we have instances where the point of interconnection for one of our wind farms is located at the transmission voltage level (>100 KV) with miles of transmission line/Generator Interconnection Facility between the wind farm aggregating system and the point of interconnection. In this instance, application of FAC-008-3 R1 and R2 is fairly straight forward but could be interpreted to require that we apply ratings criteria to non-BES portions of the aggregating system. We also have wind farms where the point of interconnection to the Transmission Owner system occurs at a main disconnect switch on each of the individual feeders at the aggregating system voltage level of 34.5 KV and at a point prior to aggregation of 75 MVA or greater. The Transmission Owner owns the aggregating system from the main disconnect switch on each feeder through a 34.5 KV bus where the feeders aggregate to >75 MVA and the transformer utilized to step up the output to transmission level voltage. For this facility, application of FAC-008-3 R1 and R2 is entirely dependent on the interpretation of the term "main step-up transformer" and results in R1 and/or R2 requiring analysis of non-BES components or which describe components only owned by the Transmission Owner and not owned by the Dispersed Generation Owner. It is recommended that FAC-008-3 R1 and R2 be simplified to state that: "The Generator Owner must have a ratings methodology and study for the following: For BES generation not included per BES Definition Inclusion I4, from and including the generator to the point of interconnection to the Transmission Owner system. For BES generation included per BES

Definition Inclusion I4, for all Generator Owner owned equipment from the point of aggregation of 75 MVA or greater to the point of interconnection to the Transmission Owner system."
No
We strongly disagree with the assertion that issues with FAC-008-3 can be addressed with guidance alone. We agree with the SAR recommendations that the applicability of FAC-008 be limited to the point of 75 MVA or above. Furthermore, we think the wording of requirements R1 and R2 is very problematic due to the uncertainty caused by the usage of the term "main step up transformer" as well as the wide variability in the possible location of "the point of interconnection with the Transmission Owner." For example, we have instances where the point of interconnection for one of our wind farms is located at the transmission voltage level (>100 KV) with miles of transmission line/Generator Interconnection Facility between the wind farm aggregating system and the point of interconnection. In this instance, application of FAC-008-3 R1 and R2 is fairly straight forward but could be interpreted to require that we apply ratings criteria to non-BES portions of the aggregating system. We also have wind farms where the point of interconnection to the Transmission Owner system occurs at a main disconnect switch on each of the individual feeders at the aggregating system voltage level of 34.5 KV and at a point prior to aggregation of 75 MVA or greater. The Transmission Owner owns the aggregating system from the main disconnect switch on each feeder through a 34.5 KV bus where the feeders aggregate to >75 MVA and the transformer utilized to step up the output to transmission level voltage. For this facility, application of FAC-008-3 R1 and R2 is entirely dependent on the interpretation of the term "main step-up transformer" and results in R1 and/or R2 requiring analysis of non-BES components or which describe components only owned by the Transmission Owner and not owned by the Dispersed Generation Owner. It is recommended that FAC-008-3 R1 and R2 be simplified to state that: "The Generator Owner must have a ratings methodology and study for the following: For BES generation not included per BES Definition Inclusion I4, from and including the generator to the point of interconnection to the Transmission Owner system. For BES generation included per BES Definition Inclusion I4, for all Generator Owner owned equipment from the point of aggregation of 75 MVA or greater to the point of interconnection to the Transmission Owner system."
No
We believe clarification of FAC-008-3 requires higher priority. See our comments concerning FAC-008-3 in Questions 2 and 3 above. The remaining concern we have is regarding timing of standard changes. We understand that the SDT has internal completion milestones of balloted standards to be sent to BOT approval November 2014, and February 2015, and this leaves more than a year for final NERC BOT and FERC approval. We understand that based on past completion history, this allows a reasonable timeframe of more than a year to expect these final steps to occur. The effort and focus of this SDT seems outstanding, however, we remain skeptical that so many standards can be changed properly to prevent a 'nonsense' non-compliant condition on the BES Definition effective date of July 1, 2014. We strongly recommend that this SDT, and appropriate members of the BOT and FERC, develop a contingency milestone at an appropriate point in the process, say February 2015, to

determine if there are any needed standard revisions in delay, that could create an unnecessary noncompliance condition on the effective date. This effort is expected to be needed to expedite any standards that have been clearly identified as needing dispersed generation applicability exemptions, but are lagging in the process and could create an unneeded issue on the effective date.
Yes
We agree with SDT that the analysis and the Mitigation of Generator Protection System Misoperations should not extend to each individual generating unit.
Yes
Yes
No
The aggregate size of the common mode failure must be considered to determine the impact to grid reliability. We suggest the existing threshold value of 75 MVA. In addition, we believe that this would have to do more with a setting associated with PRC-019, PRC-034, and PRC-025. These common mode failures would not be a classical PRC-004 operation analysis because the equipment is not in-scope.
Yes
No
As worded, this question does not agree with the white paper. Xcel Energy supports the position put forth in the white paper, which states that R4 and R5 of the VAR-002-2b standard would not be applicable to the individual units.
No
Individual
Tim Brown
Idaho Power Company
Yes
No
See comments on proposed changes to PRC-004 below. Otherwise the approaches seem reasonable.
Yes
Yes

Yes
No
Based on the discussion for TOP-001-1a R7 and TOP-002-2.1b R14, the SDT might consider the analysis of a trip of greater than 20 MVA. The rationale seem similar that if the loss of 20 MVA of generation is necessary to plan for, then it would be significant enough to analyze when it lost.
Yes
Yes
since 75MVA has been determined to be cut off for significance to the reliably operation of the BPS, I would think a loss of any 75MVA generating resource would be considered equally (not considering MVAR capability!)
Yes
No
No
Individual
Barbara Kedrowski
Wisconsin Electric Power Co
No
The CIP standards must be modified to remove the individual dispersed generator controls from the scope. Given the direction in FERC Order 791 to develop actual auditable requirements for low impact BESCS, the argument that CIP doesn’t need to worry about applicability due to no real requirements is a faulty argument.
No
The VAR-002 target applicability should be at the point of interconnection.
No
We think that the target applicability for MOD-032 should be on the aggregate facility level.
Yes
Yes
Yes
Yes

The second paragraph in this section in part states “Should these protection elements fail to remove the generating unit for this scenario, the impacts would be limited to the loss the individual generating unit and potentially the next device upstream in the collection system of the dispersed generation resource”. If the next device upstream is the collection system and it is greater than 75 MVA then this argument needs additional clarification. If the applicability of dispersed power-producing resources is not changed, we would ask the SDT to provide guidance for the testing of these elements considering the safety, physical constraints and elements that are part of protection systems that were not considered in PRC-005 as it is written. For example, parts of the protection systems of wind turbines cannot be accessed when they are running because of safety reasons. In addition, the system protection elements of some dispersed power-producing resources include molded case circuit breakers, power circuit breakers with trip units, UPSs and other devices that are not currently in PRC-005.
Yes
Agreed as long as the “large number” is greater than 75 MVA.
No
Technical justification should recognize that an individual dispersed generating resource does not provide sufficient reactive resources to provide reliability of the BES.
No
We would agree if the question included …transformers are NOT subject to the R4 and R5… In addition, has the DGR SDT considered coordination with Project 2013-04, Voltage and Reactive Control, VAR-002-3 on any proposed changes regarding clarifying applicability?
Yes
Executive summary of white paper: "… the intent of this effort is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed generation resources, where the status quo does not create a reliability gap.” We disagree with the language about “being applied over time” because each Regional Entity could have been applying it differently. Section 5.10.1 PRC-001-1.1: We agree that the SDT should push this issue on the current Project SDT’s, but what happens in the interim? Will the Project teams for 2007-06 and 2014-03 finish in time so that our compliance is not affected? Section 5.10.11 PRC-024: Note that the SDT “ … has determined it is necessary to require that Protection Systems applied on both the individual generating units, as well as any aggregating facilities, are set within the “no-trip zone” referenced in the requirements to maintain reliability of the BPS.” SDT says no changes to applicability are required, but states an RSAW or guidance should specify compliance evidence requirements. We did not think an RSAW could specify compliance requirements; only standards could specify compliance requirements.
Individual
Jo-Anne Ross
Manitoba Hydro
No

The SDT should consider modifications to FAC-001-1. Requirement R1 notes that Facility connection requirements for “Generation Facilities” shall be documented. It should be clear in the scope of the standard that any special connection requirements for dispersed power producing resources (Inclusion I4) should be documented. NERC IVGTF 1-3 recommended reactive power requirements be clearly defined as well as any special modeling requirements (eg. aggregation), for example. Frequency response requirements for both under and overfrequency should be documented in FAC-001-1. Also the SDT should consider modifications to VAR-001-3 to include language more appropriate for DGR. Automatic Voltage Regulator in R4 is applicable to conventional synchronous generators and a generic plant-level volt/var controller is more applicable to DGR with a voltage controller controlling the voltage at the point of interconnection. It should be clear that a voltage or Reactive Power schedule can be given by the TO to a DGR. The schedule may be influenced by the technology (eg. switched capacitor banks vs static var compensator). The SDT correctly identifies some standards, such as the MOD standards, where “the SDT will consider the need to develop guidelines for dispersed generation resource modeling and therefore recommends consulting other groups” that are currently working on these issues. This is inconsistent with the statement in the same section “The existing and proposed modeling standards are sufficient for modeling dispersed generation resources”. As such it is suggested that the SDT may wish to consult with these groups prior to establishing priorities on some standards.
Yes
Yes
We agree this would be helpful however, we suggest using the term “common and electrically similar” dispersed power producing resources rather than “common”. Dispersed power producing resources with sufficiently different electrical characteristics from a modeling perspective, may be installed at the same location.
No
In addition, changes to FAC-001-1 should be added to the high priority and changes to VAR-001-3 added to the low priority list. The justification for establishing “High” vs “Medium” priority levels for standards is not clear. It is possible that the choice of wording does not clearly explain the difference between the two levels. It is suggested that these two priority level justifications be reworded for clarity.
No
Section 5.10.4 relates applicability of PRC-004 to PRC-024 but is not clear what is proposed to be changed in PRC-004. The current applicability used in PRC-024 is for all generating units with some technical modifications for asynchronous units. We agree that the applicability should not apply to individual units within a DGR.
No
One of the areas of concern with DGR is the ability to ride through disturbances (e.g. low voltage ride through). We disagree that a trip greater than 75 MVA should only be considered as this would remove a lot of DGR from consideration. The timing of a disturbance may correlate with a period when the output of the DGR is low. In this case, the reliability impact

of the lost generation may be low but the misoperation may point to a problem that could occur at any output level. Perhaps, to set a reasonable boundary, protection misoperation that occurs when DGR had an output of 20 MVA or greater should be analyzed in PRC-004.
Yes
Yes
Common mode failures, such as the ability to ride through low voltages or low frequency, can impact reliability. It is possible to have groups of DGR in close electrical proximity that may also experience the same common mode failure, making the system more prone to underfrequency or other reliability event. Ground fault relays that are not coordinated can also result in loss of DGR for BES faults. The impact would depend on the definition of “large”, the location of the dispersed generation resource, whether tapped off of a major BES high voltage transmission tie or not, and the type of common mode failure. For example if it is tapped off a BES transmission tie line, special considerations , such as installing a three ring breaker at the POI or adding/modifying an SPS may be necessary to minimize the impact to BES reliability.
Yes
The individual generator transformers within the DGR can be excluded in R4 and R5 in favor of the main aggregating transformer connected to the BES. Revised applicability should also be included in R3. There can be power factor correction capacitors located within each individual generator transformer. Only major sources of Reactive Power that impact the BES should be included in the applicability of R3. Terminology of “automatic voltage regulator (AVR)” could be adjusted to in VAR-002-2b to reflect the technology used in a DGR – see comments to Question 1.
No
If the applicability is revised as per Question 9, additional guidance should not be needed.
Yes
It is suggested that the data provided in the table in Section 5 (page 11) be rearranged for clearer presentation of the information. Subtotals for “NERC Standards” and “Region-specific Standards (*Out of Scope)” may be placed at the end of their respective categories rather than at the beginning.
Individual
John Pearson
ISO New England
No
PRC-004-2.1a should not be modified to exclude dispersed power producing resources. From ISO New England’s perspective, it is important to know about relay misoperations in order to maintain system reliability. This extends to individual units that make up an aggregated dispersed power producing resource, especially when one considers the potential that similar practices would be used in setting each of the protection systems applied to individual units .

FERC has explicitly recognized this in its March 20, 2014 Order Approving Revised Definition, where it stated that: “[f]or example, a wind farm larger than 75 MVA can affect reliability if all of its wind turbines trip offline simultaneously after just a slight fluctuation in voltage or frequency. Therefore, because variable generation can impact the interconnected transmission network, we anticipate that wind plant owners whose facilities meet the inclusion I4 criteria who seek to exclude individual wind turbines from the bulk electric system through the exception process will be infrequent.” See North American Reliability Corporation, 146 FERC ¶ 61,199 (2014) at P 48.
No
The applicability of PRC-004 should not be modified as explained above in the answer to Question No. 1.
Yes
With respect to MOD-032, it is important that generators provide accurate models of each individual unit. Therefore, if all units are identical, then providing aggregate information may be sufficient. However, if units are not identical, then generators should be required to provide individual models.
No
PRC-004 and associated relay misoperations are important for reliability. Efforts to reduce it’s applicability should not be a priority.
No
The justification provided by the SDT is contrary to FERC’s March 20, 2014 Order (please see our answer to Question No. 1 above).
No
We do not agree with this approach because limiting the analysis requirement to a trip of greater than 75 MVA only accounts for very large occurrences that could be unusual. Smaller occurrences, however, may predict an unusual large occurrence that could impact reliability especially when one considers the potential that similar practices would be used in setting each of the protection systems applied to individual units.
No
In general, relay maintenance is a vital part of system reliability and reducing the applicability of the standard seems counter to good utility practice.
Yes
Yes, as explicitly recognized by FERC, a wind farm larger than 75 MVA can affect reliability if all of its wind turbines trip offline simultaneously after just a slight fluctuation in voltage or frequency.
No
In general, providing voltage regulation at the point of aggregation is acceptable. However imbedded dynamic devices may affect aggregate voltage performance. The “clarification” needs to address this.
No

There is no need to modify the applicability of R4 and R5 of VAR-002-2b. The information under R4 has to be provided only upon request of the Transmission Planner and Transmission Operator. If this information is not necessary, it should not be requested and, accordingly, there is no need to modify the standard. Similarly, R5 is only applicable if the Transmission Operator requests a change to the tap setting. The Transmission Operator should only do this when necessary; therefore, there is no need to modify the applicability of the standard. In addition, other reactive devices, such as embedded dynamic reactive devices,may affect aggregate voltage performance and should be addressed.
No
Individual
Heather Bowden
EDP Renewables North America LLC
Yes
Section 4.2.2 of the white paper notes that the age of dispersed generation resources affects their ability to provide reliability services. However, identification of relevant standards as described in the Technical Discussion does not refer to age or ability. It is not clear what role those characteristics play in identifying relevant Standards.
No
The SDT should be as precise as possible in the guidance it provides, since that guidance will be the basis for significant revisions to the numerous Standards identified to date. EDP Renewables North America LLC (EDP Renewables) recommends that the SDT define the terms used to specify “Target Applicability” of the Standard revisions. If the terms “Point of common control”, “point where aggregated to > 75 MVA”, and “Aggregate Facility Level” are intended to have different meanings, these should be specified. A better approach would be to use the Point of Interconnect as the Target Applicability. This is a well defined industry term. Using the other terms could lead to misunderstanding, and/or result in inconsistency due to individuals’ interpretations.
No
EDP Renewables recommends that the SDT specify how common components should be aggregated into “Elements” to prevent confusion and inconsistency across Standards and regions. Given the variety of technologies lumped under the dispersed generation rubric, a technically justified, technology neutral approach for the aggregation methodology is needed. The critical mass components must attain to be treated as Elements must be clearly established. EDP Renewables requests confirmation that the statement “loss of significant number of units” in section 4.2.3. means “more than 75MVA of aggregated capacity”.
Yes
No

Instead of opening a debate about the relationship between misoperations and common mode trips, PRC-004's applicability should be limited to individual protection system components that affect > 75 MVA of capability.
No
PRC-004's applicability should be limited to any individual protection system component that affects > 75 MVA of capability. Additionally, the reliability of the Bulk Electric System would not be compromised should the individual generator trips occur over a period greater than sixty cycles. Within the White Paper, the SDT denotes that, "Protection system maintenance on individual generating units at a dispersed generation facility would not provide any additional reliability benefits to the BES…" The applicability of PRC-001, PRC-004, and PRC-005 should be congruent.
Yes
The applicability of PRC-001, PRC-004, and PRC-005 should be congruent.
No
For consistency and to prevent confusion, a specific capability limit (>75 MVA) should be used. It is widely agreed that until capability aggregates to that level, BES reliability is not threatened.
No
Dispersed generation resources are often required to install reactive devices as a condition of interconnection. The applicability of VAR-002 should specify how these devices should be treated when establishing voltage schedules and performance expectations. This may be a Standard that should take into account the capability ("older dispersed generation resources") of a resource. Further, if dispersed generation is to include storage devices, care should be taken that requirements are technology neutral. Rather than using the Agregate Facility Level, the reference point for maintaining the voltage schedule, usually the Point Of Interconnect, shall be used.
Yes
It is necessary to exclude these transformers form requirements R4 and R5.
Yes
It would be beneficial if the applicabilities were defined within the NERC Glossary. It would be prudent to include the same applicability recommendation to each of the Project teams (i.e. Project 2014-03 and Project 2014-01), to ensure that both PRC-001 and PRC-005 view the same applicability as it applies to dispersed generation resources.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC,

RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
Yes
The SDT states on p.7 of the Whitepaper that “Dispersed generation resources are often considered to be variable energy resources such as wind and power, “ but, “This description is not explicitly stated in the BES definition.” The SDT’s comment that “NERC and FERC characterize variable generation in this manner,” is helpful, but the absence of a formal definition of Dispersed Generation Resources remains a concern. We request that the term Dispersed Generation Resources be formally defined in the NERC Glossary.
Group
FirstEnergy
Cindy Stewart
Yes
FE questions the need for both PRC-005-1.1b and PRC-005-2. Why not just focus on PRC-005-2
Yes
Yes
Yes
Approach seems logical for prioritization of Standards to be revised.
Yes
How will this Project be coordinated with the current efforts on Project 2010-05.1, Phase I of Protection System Misoperations.
Yes
It is consistent with the requirement for existing BES identified generating units.
Yes
Required reporting of aggregated facility equipment consistent with BES definition is the proper methodology.
Yes

The BES definition has provided technical justification for a threshold of 75 MVA of aggregated generation viewed as having reliability impact on the BES. The PRC Standards focus on loss of this and higher levels of generating resources.
Yes
No
If the individual generator transformers are below the BES defined level then R4 and R5 should not apply.
No
Group
DTE Electric
Kathleen Black
Yes
No comments
No
See Question 3 comments
No
More clarity would be appreciated regarding the individual vs aggregate approach for the facility ratings Standard. Guidance on the scopeof equipment to be rated for DGRs would be helpful.
No comments
Yes
Yes
The applicability statement should be clear in that individual generating unit trips should only be analyzed relative to comon mode trips.
Yes
Yes
BES reliability could be impacted if a concurrent loss of individual generating units aggregating to nore than seventy five MVA occurs.
No comments
No comments
No
Individual

Scott Langston
City of Tallahassee
Yes
Yes
Yes
Yes
No
Tal agrees with the exclusion of aggregate levels of generation below 75MVA. Tal would prefer to see justification of the 75 MVA brightline for the requirement of protection devices to be included under PRC-005.
Yes
No
Group
NEA Joint Commenters (NextEra, Exelon and MidAmercian)
Silvia Parada Mitchell
No
NextEra Energy, Inc., Exelon, and MidAmerican (Joint Commenters NEA) jointly submit these comments. The Joint Commenters NEA individually and collectively own and operate most of the variable generation in North America, and, therefore have unique perspective and expertise on the issues presented in the April 14, 2014 Draft White Paper Proposed Revisions to the Applicability of NERC Reliability Standards NERC Standards Applicability to Dispersed Generation Resources (Draft White Paper). The Joint Commenters NEA appreciates the hard work that is represented in the Draft White Paper, and the technical discussion of the Standards. The Joint Commenters NEA also appreciates the identification of three Standards that for technical reasons should be revised; however, the Joint Commenters NEA are concerned that the White Paper goes much further than the scope of the Standards Authorization Request and recommends that the drafting team focus its efforts solely on

three identified Standards. Specifically, the Joint Commenters NEA supports the Standards Drafting Team (SDT) moving forward with revisions to PRC-004-2.1a, PRC-005 (relevant versions) and VAR-002. The Joint Commenters NEA do not support the SDT moving forward on work of any other Standard, because there is not a clear and justified technical reason at this time to require revisions to any more Standards. Specifically, the Joint Commenters NEA recommend that the SDT hand off all other observations in the Draft White Paper to NERC Staff to work with the appropriate NERC technical committees to develop and publish any guidance, etc needed for those Standards.
No
The Joint Commenters NEA only agree with the recommended revisions to PRC-004-2.1a, PRC-005 (relevant versions) and VAR-002 at this time, and recommend that the SDT focus on and complete these changes as soon as possible. The Joint Commenters NEA also recommend that the SDT also hand off the suggested guidance issues to NERC Staff to work with the appropriate NERC technical committees to develop and publish any guidance, etc needed for those Standards. The Joint Commenters NEA are concerned that some of the issues raised in the White Paper implicate compliance rather than technical issues, and, thus believe stakeholders are best served with these observations being reviewed by the NERC technical committees. For example, TOP-001, TOP-003 and TOP-006 as discussed in the White Paper do not raise to the level of a change to the requirements, and, thus, guidance can be developed by NERC staff and the Operating Committee with regards to how to apply to dispersed power producing resources, as these standards all relate to communication of real-time status, future outage planning and capabilities of dispersed generating resource. While communication of these data may be feasible from a technical perspective this could be construed as a compliance issue that can be resolved through guidance rather than standard revisions.
Yes
The Joint Commenters NEA agrees that revisions are not necessary and guidance may be helpful for the following standards FAC-008-3, PRC-019-1, PRC-024-1, PRC-025-1, MOD-025-2 and MOD-032-1. As mentioned above, the Joint Commenters recommend that these Standards and associated observations be provided to NERC Staff for additional work with the relevant NERC technical committee to consider any needed guidance. For FAC-008-3 in particular, the Joint Commenters feel that the guidance document should implicate standard requirements for Dispersed Generation from the point of aggregation greater than 75 MVA, up to the point of interconnect as was indicated in the SAR. For FAC-008, the guidance should address the issue in the SAR, which transformer (point of aggregation) is in scope. Also, why in the FAC-008 analysis in the Whitepaper is there reference to SOL's? The second paragraph of the FAC-008 analysis seems out of scope.
No
Although the Joint Commenters NEA generally recognize the need to prioritize the SDTs work, it is concerned that the SDT undertook a task that is arguably well outside the scope of the SAR presented to the Standards Committee to include "consideration is necessary for other requirements that affect the interaction of a Balancing Authority (BA), Transmission Operator

(TOP), or Reliability Coordinator (RC) with individual BES Elements." As mentioned above, the Joint Commenters NEA recommends that the SDT focus its efforts solely on the implementations of revisions to PRC-004-2.1a, PRC-005 (relevant versions) and VAR-002.
Yes
The Joint Commenters NEA believe that the technical basis for the Standard change for I4 BES dispersed generation (i.e., wind and solar) is clear and supported. As such, the Joint Commenters NEA also concur with the SDT's decision to defer to the BES Reference Document's description of I4 "dispersed power producing resources" in the analysis as noted on page 5 of the Draft White Paper, as this description clearly is intended to identify the unique and "non-traditional" variable generation such as wind and solar, rather than traditional resources such as fossil generating resources.
Yes
The Joint Commenters NEA believe that the technical basis for the Standard change for I4 BES dispersed generation (i.e., wind and solar) is clear and supported. As such, the Joint Commenters NEA also concur with the SDT's decision to defer to the BES Reference Document's description of I4 "dispersed power producing resources" in the analysis as noted on page 5 of the Draft White Paper, as this description clearly is intended to identify the unique and "non-traditional" variable generation such as wind and solar, rather than traditional resources such as fossil generating resources.
Yes
The Joint Commenters NEA believe that the technical basis for the Standard change for I4 BES dispersed generation (i.e., wind and solar) is clear and supported. As such, the Joint Commenters NEA also concur with the SDT's decision to defer to the BES Reference Document's description of I4 "dispersed power producing resources" in the analysis as noted on page 5 of the Draft White Paper, as this description clearly is intended to identify the unique and "non-traditional" variable generation such as wind and solar, rather than traditional resources such as fossil generating resources. The drafting team should take care to address only issues related to the unique nature of these non-traditional resources and not duplicate issues already addressed in the PRC-005 standard and it's supporting documents such as protection systems at the interfaces.
Yes
For the purposes of limiting misoperations reporting to an entire site as opposed to individual resources.
Yes
The Joint Commenters NEA believe that the technical basis for the Standard change for I4 BES dispersed generation (i.e., wind and solar) is clear and supported. As such, the Joint Commenters NEA also concur with the SDT's decision to defer to the BES Reference Document's description of I4 "dispersed power producing resources" in the analysis as noted on page 5 of the Draft White Paper, as this description clearly is intended to identify the unique and "non-traditional" variable generation such as wind and solar, rather than traditional resources such as fossil generating resources.
Yes

The Joint Commenters NEA believe that the technical basis for the Standard change for I4 BES dispersed generation (i.e., wind and solar) is clear and supported. As such, the Joint Commenters NEA also concur with the SDT's decision to defer to the BES Reference Document's description of I4 "dispersed power producing resources" in the analysis as noted on page 5 of the Draft White Paper, as this description clearly is intended to identify the unique and "non-traditional" variable generation such as wind and solar, rather than traditional resources such as fossil generating resources. In particular there are no reliability benefits to be gained by requiring R4 and R5 to be applicable to the individual generator transformers at a dispersed generation facility; as such, these requirements should be implemented on the aggregating equipment only.
Yes
Section 4.2. Dispersed generation resources are often variable energy resources such as wind and solar. Section 4.2.1. The generating capacity of individual dispersed generating modules can be as small as a few hundred watts to as large as several megawatts. The utilization of these small generating units' results in a large number of units (e.g., several hundred wind generators or several million solar panels) installed collectively as a single facility that is connected to the transmission system.
Individual
Bill Fowler
City of Tallahassee, TAL
Yes
Yes
Yes
Yes
No
TAL agrees with the the exclusion of aggregate levels of generation below 75MVA. TAL would prefer to see a justification of the 75MVA brightline for the requirement of protection devices to be included under PRC-005.
Yes
No

Individual
Karen Webb
City of Tallahassee - Electric Utility
Yes
Yes
Yes
Yes
No
TAL agrees with the the exclusion of aggregate levels of generation below 75MVA. TAL would prefer to see a justification of the 75MVA brightline for the requirement of protection devices to be included under PRC-005.
Yes
No
Group
Duke Energy
Colby Bellville
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Duke Energy agrees with the SDTs recommendation that if a trip of generation resulting in the aggregate loss of 75MVA or greater occurs, then an analysis of potential Misoperations of the individual generating units should take place.
Yes
No
We believe the SDT may have misstated question 10. We do not believe that individual generator transformers should be subject to R4 and R5. The White paper leads the reader to believe that this question should be asking if we agree that individual generators should "not" be subject to R4 and R5. Please clarify the SDTs intent for this question.
No
Individual
Larry Heckert
Alliant Energy
No
We understand the SDT's concern with regard to a common mode trip of several generating units. However, we do not support any language that would effectively bring turbine control systems in scope for PRC-004, in lieu of protection systems which is the current scope of PRC-004.
No
Group
SPP Standards Review Group
Shannon V. Mickens

Yes
Yes
The chosen approaches seem reasonable.
Yes
Yes
Yes
Yes
Yes
Yes
With significant numbers of dispersed generation resources currently in existence and more being placed into service daily, the issue of a, misoperation (common mode) of a large number of individual generating resources becomes more probable. Not that such an event would be any more detrimential to the reliability of the BES than the loss of a comparable amount of traditional generation, the impact would be about the same.
Yes
Yes
Yes
We note that the SDT swings back and forth between the BPS and BES. Shouldn't we restrict ourselves to the BES since the reliability standards are about preserving the reliability of the BES? We don't quite understand the statement that begins the Section 4.2.1 Design Characteristics. It states 'For dispersed power producing resources to be economically viable, it is necessary for the equipment to be geographically dispersed.' Could the SDT expand on this? Use a lower case 't' in 'the' in the italicized sentence at the end of Section 5.4.4 FAC-008 – Facility Ratings. A similar error appears in Section 5.7.7. The opening statement in Section 5.6.2 IR0-005 – Reliability Coordination – Current Day Operations mentions only one of the requirements in the standard that applies to Generator Operators which does not provide a total picture of the purpose of the standard. The statement refers to Requirement R10. However, Requirement R6 also applies to Generator Operators regarding the development of action plans to address potential or actual SOL, DCS or CPS violations. Although the conclusion reached in Section 5.6.2 won't change with this additional information, it does provide a fuller picture of what the Generator Operator's responsibilities are with regards to the standard. Something appears to be missing at the end of the 3rd line of the 3rd (R3) paragraph under

Section 5.10.1. My quess is that the SDT meant to say '…non-operation of an interconnected entity's Protection Systems,…' However, 'protection' is not capitalized in the text, so I'm unsure just what belongs here. Replace the 'is' in the 1st sentence of the paragraph under Section 5.10.2 with 'has been' such that the sentence reads '…, which has been adopted by the NERC…'. There are numerous references to Real-time in the White Paper. Be sure to use the NERC Glossary spelling in those references. Delete the extra 'in' in the 6th line in Section 5.11.3.1. The phrase 'to the nature' in the 1st bullet of Section 5.11.3.2 doesn't seem to fit nor add anything to the sentence. I'd suggest deleting it. Delete the 'the' in the last line of that same paragraph and replace it with 'its host'. Delete the plural 's' in 'resources' in the 1st line of the last paragraph of Section 5.11.3.3. Replace 'the SDT project' in the 8th line of the 2nd paragraph under Section 5.11.4.2 with 'Project 2014-01'. In that same paragraph, delete the 'in' in the next to last line in the italicized sentence at the end of the paragraph. These same errors appear in Section 5.11.5. The conclusion in the italicized sentence at the end of Section 5.14.1 is not supported by the sentence immediately preceding it.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes
No
See comments specific to VAR-002 in Q9 and Q10 comments.
Yes
Do the "aggregated facilities" in Appendix B refere to > 75 MVA aggregation points? PRC-024 needs to pertain to common settings for individual generating resources where incorrectly set protection elements could cause > 75 MVA to trip where is it not deisred. The region specific PRC-006 standards should include mention of common mode effects (e.g. for SERC, one must specify the # MW lost when the UF protection activates - this should include the aggregated MW of all units set similarly). This question is a difficult to answer not knowing what the specific guidance will be.
Yes
Yes
Yes
Yes

The current revision project to PRC-005 is 2007-17.3 (it is shown incorrectly in the last paragraph of section 5.10.6)
No
Only in rare cases of multiple contingencies might a misoperation of a large number of the individual generating resources at a dispersed generation resource site impact BES reliability.
Yes
VAR-002-2b should apply only to dispersed generation resources that are designed to provide voltage and/or reactive support for the BES. This includes those where voltage or reactive sources (cap banks, reactor banks, static var devices, plant voltage outer-loop control, etc.) which are installed specifically to provide system voltage and reactive support at the point of interconnection or aggregate facility level. Dispersed generation resources that do not have such capability by design should be exempted from VAR-002-2b.
Yes
It should be clear that the plant step-up transformer (HV side > 100kV) should be included in the R4 and R5, but that any individual resource transformer (HV side < 100kV) is not included in the scope.
No
Group
ACES Standards Collaborators
Jason Marshall
No
(1) The drafting team has done an excellent job reviewing all of the standards that apply to GOs and GOPs and also identifying some of the ancillary issues such as the interaction of BAs, TOPs, and RCs and dispersed generation resources. However, we do believe a deeper dive is required with some of the standards to identify additional issues and that the standards need to be reviewed from the perspective of whether a GO/GOP has only dispersed generation resources and no other resources. Specific examples of our concerns are discussed below. (2) For example, while EOP-004-2 at first glance appears to apply to the function and not the individual elements, closer inspection reveals that a GO with dispersed generation would have to report for each individual unit as the dispersed generation site when there is “damage or destruction of its Facilitiy that results from actual or suspected intentional human action”. The definition of Facility would include individual wind turbines since they are classified as part of the BES. This literally means that if there was intentional damage caused to 1 MVA wind turbine at an applicable dispersed generation resource site, the BA, GO, and GOP would all have to report intentional human damage per EOP-004-2. There are other thresholds for reporting that would apply in EOP-004-2 as well. These need to be reviewed further. (3) If EOP-005-2 is reviewed from the perspective of applying the standard to a GOP that only operates dispersed generation resources, we question if the standard should apply at all. Can dispersed generation resources be Blackstart Resources? If dispersed generation resources

cannot serve as Blackstart Resources, only one requirement (R18) would apply and the GOP would be burdened with proving that the Blackstart Resource requirements do not apply during every compliance monitoring event. Furthermore, what possible role could a GOP with only dispersed generation resources play in restoration. If they have no role, why would they need to pariticpate in "restoration drills, exercises, or simulations". (4) We disagree that limiting the applicability of the NUC standard to exclude dispersed generation resources would create a reliability gap. A Nuclear Plant Generator Operator cannot practically rely on variable output resources such as dispersed generation resources to meet its NPIRs. Thus, limiting applicability does not create realibility gap. (5) We disagree with the determination for TOP-001-1a R6 in the whitepaper. The requirement requires the GOP to provide "all available emergency assistance". From a reliability perspective, what "emergency assistance" would the GOP of a dispersed generating resource be expected to supply. Shut down the units or reduce output? These are examples of actions that would be issued via a directive and are covered under IRO-001-1.1 R8 and TOP-001-1a R3 directive. Thus, the requirement does not need to apply to dispersed generation resources. (6) For TOP-003-1 R1, the whitepaper should explain that the standard should be applied on an aggregate basis and not an individual resource basis. There is no need for the Transmission Operator to be aware of individual wind turbine outages. They only need to know the aggregate outage amount.
No
agree conceptually with the approach overall but have identified a few standards where we disagree with the assessment. Those are documented in the first and third questions.
No
We agree with all standards except PRC-025. We do not understand why PRC-025 would need to apply to individual generating units in a dispersed generator resource. This would imply that the loss of a single unit at these dispersed generation resource sites would have a reliability impact which would be counterintuitive to this entire standards project. Futhermore, it is not consistent with the drafting team's approach that standards that apply to individual generating elements need to be modified. The whitepaper may even contradict the applicability section 3.2.5 of the standard that states "Elements utilized in the aggregation of dispersed power producing resources" which suggests the standard applies to individual generating elements and not the GOP as a whole. We suggest that either PRC-025 should be added to the standards that need the applicability modified or a better explanation for why it does not need to be modified should provided in the whitepaper.
Yes
We agree conceptually with the approach.
We believe adequate justification has been provided.
Yes
The SDT's approach is supported by the fact that the threshold for dispersed generation resources is 75 MVA for inclusion in the BES. If the facility impacts the BPS reliability, it will be included in the BES. Thus, a loss of less than 75 MVA of dispersed generation resources by definition cannot impact BPS reliability and, thus, analysis of misoperations of Protection Systems is unnecessary when less than 75 MVA of generation will be lost.

Yes
We believe adequate justification for the revisions have been provided.
No
For the vast majority of dispersed generating resources, we do not believe that a common mode failure for that dispersed generating resource site would be impactful to reliability in most cases. First, most of these sites are not that large. Second, because the output is variable, these resources must be backed up with operating reserve to account for their variability. Third, there are other NERC standards that require operation of the BES to withstand the next contingency so the loss of entire wind farm or solar array will not be impactful to reliability unless another standard is concurrently violated.
Yes
We believe adequate justification has been provided.
Yes
We believe that guidance or modification to the standard is necessary to ensure that VAR-002-2b only applies to a step-up transformer at the interconnection point to the BES for the dispersed generating resource.
Yes
(1) Although there was discussion of the NPCC and SERC versions of PRC-006-1, we did not see any discussion regarding the NERC version of PRC-006. This needs to be included. (2) We are concerned about the coordination of some changes with other drafting teams identified for several requirements in the whitepaper. Some drafting teams have already reached a point where it is too late for coordination. For example, PRC-001 is to be coordinated with the Project 2014-03 TOP IRO drafting team. However, that drafting team is currently preparing documentation to post for public comment in May and will have completed preparations by the time this comment is received. Better coordination with other drafting teams appears to be warranted.

Question 4 – Response: Yes

Comments: The Implementation Plan can be read that it obligates applicable entities to complete the initial risk assessment in Requirement R1, on or before the effective date of the standard. The implementation plan should be adjusted.

The following is a suggestion to facilitate reading of the standard and stay whitn defined terms without introfucing new terms which are undefined: For all requirements: Replace the expression "Transmission stations and Transmission substations" with "Transmission facilities". Otherwise, please explain why such a distinction is necessary.

While the requirement for unaffiliated third party verification of the physical security plan is something required by the FERC in its order, the mandate is misguided and will lead to security breaches while at the same time adding no incremental value to the physical security plan. The utility, which owns the assets, is already highly incentivized to put together a good security plan to avoid loss of its facilities to terrorism without third party verification. The utility may decide to use security consultants to help develop the plan if it involves new, state of the art physical security topics outside the utilities experience base. On balance the third party verification requirement outlined in R6 regarding the physical security plan is unneeded.

Additional comment received from Marcus Pelt, Southern Company

"The wording of Requirement R2.s, as it stands currently, could be interpreted to place requirements on the unaffiliated third party verifier when the responsible entity is actually the Transmission Owner. Southern recommends that R2.2 be reworded as follows to address this concern:

Proposed R2.2
2.2 The responsible Transmission Owner shall ensure the unaffiliated third party verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment. The unaffiliated third party verification may, but is not required to, include recommended additions or deletions of Transmission station(s) or Transmission substation(s)."

Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources

The Project 2014-01 (Project) Standards Applicability for Dispersed Generation Resources (DGR) standards drafting team (SDT) thanks all commenters who submitted comments on the DGR Draft White Paper proposing revisions to the applicability of NERC Reliability Standards to DGRs (White Paper). The White Paper was posted for an informal comment period from April 17, 2014 through May 5, 2014. Stakeholders were asked to provide feedback on the White Paper through a special electronic comment form. There were 24 sets of comments, including comments from approximately 82 different commenters from approximately 54 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

The SDT encourages commenters to review the SDT's responses to ensure all concerns have been addressed. The SDT notes that a majority of commenters agree with the SDT's recommendations as detailed in the White Paper, but that several commenters expressed specific concerns about the content of the White Paper and the Project in general. Some comments supporting the SDT's recommendations are discussed below but in most cases are not specifically addressed in this response. Also, several comments in response to specific questions are duplicated in other questions, and several commenters raise substantively the same concerns as others. Therefore, the SDT's consideration of all comments is addressed in this section in summary form, with duplicate comments treated as a single issue.

Summary Consideration

Industry generally agrees with the SDT's recommendations to make applicability changes or provide additional guidance to account for the unique characteristics of DGRs in the NERC standards as explained in the White Paper. However, there are significant disagreements and apparent confusion expressed by commenters on the DGR Standards Authorization Request (SAR) and some of the recommendations contained in the White Paper. The SDT has carefully reviewed and considered each stakeholder comment and has revised or will revise its recommendations where suggested changes are consistent with SDT intent and industry consensus. Moreover, the SDT made or will make several clarifications to its recommendations to more closely align the White Paper with SDT intent and industry consensus. The SDT's consideration of all comments follows.

1. General Scope and Objective of the SAR and the DGR Project

A. Scope

Some commenters are concerned that the White Paper goes much further than the scope of the SAR and recommends that the SDT focus its efforts solely on three identified high-priority standards. Those commenters do not support the SDT moving forward on work of any other standard because, according to commenters, there is not a clear and justified technical reason at this time to require revisions to any more standards. Specifically, some commenters recommend that the SDT hand off all other observations in the White Paper to NERC staff to work with the appropriate NERC technical committees to develop and publish any guidance needed for those Standards. The SDT disagrees that the SAR limits scope to only the three identified high-priority standards, and industry consensus clearly supports that position. For these reasons, the SDT conducted a review of all standards. The SDT intends to coordinate as much as possible with other SDTs on those applicable standards for which current SDT work is underway. The SDT also notes that a parallel but separate effort to develop industry guidance on DGR applicability is underway that includes members of the SDT, NERC staff, and independent industry experts.

At least one commenter believes that the White Paper needs to consider many system configurations, reasoning that not all configurations are the same. The SDT understands that a GOP's voltage controlling equipment and Elements differ based on the type of generation facility, and that indeed system configurations vary. However, a "one size fits all" approach would not be appropriate due to the unique characteristics of dispersed generation. Each generation facility may have a different methodology to ensure the facility has an automatic and dynamic response to changes in voltage to ensure the voltage schedule is maintained. It is implied, for example, in NERC VAR-001-3 that each GOP and TOP should understand capabilities of the generation facility and the requirements of the transmission system to ensure a mutually agreeable solution and schedule is used.

Some commenters commented or made suggestions on the SDT's consideration and treatment of Regional standards. With regard to the Regional standards, the SDT may make recommendations to the Regions; however, revisions to the existing Regional standards will be undertaken by the Regions.

B. Timing

Several commenters encourage the SDT to proceed expeditiously on this Project, particularly on developing revisions to the identified high-priority standards, i.e., PRC-004-2.1a, PRC-005, and VAR-002, so that owners can proceed with implementation of the BES definition and these standards without unnecessary interim work. The SDT agrees and is therefore proceeding as expeditiously as possible with work on the high-priority standards. The SDT remains on schedule to complete its recommendations on the high-priority standards by the November 2014 NERC Board of Trustees (Board) meeting, with recommendations on the medium- and low-priority standards by the February 2015 Board meeting.

C. Status Quo

At least one commenter disagrees with the White Paper language that states that the intent of the Project is to "maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed generation resources, where the status quo does not create a reliability gap" because each Regional Entity could have been applying it differently. The SDT will consider this observation in review and revision of the White Paper and make revisions if changes are necessary to more closely align the White Paper with SDT intent and industry consensus.

D. Target Applicability

Several commenters express concern and confusion on the term "Target Applicability" and the individual versus aggregate approach. For example, at least one commenter recommends that the SDT define the terms used to specify "Target Applicability" of the standard revisions. According to that commenter, if the terms "Point of common control," "point where aggregated to greater than 75 MVA," and "Aggregate Facility Level" are intended to have different meanings, these should be specified. At least one commenter suggests adding definitions to the NERC Glossary of Terms. Another commenter believes that a better approach would be to use the Point of Interconnect as the Target Applicability, as it is a well-defined industry term, noting that using the other terms could lead to misunderstanding or result in inconsistency due to individual interpretations. Another commenter questions whether "aggregated facilities" in Appendix B refer to greater than 75 MVA aggregation points.

Another commenter recommends that the SDT specify how common components should be aggregated into "Elements" to prevent confusion and inconsistency across standards and regions. The commenter believes that given the variety of technologies lumped under the dispersed generation rubric, a technically justified, technology-neutral approach for the aggregation methodology is needed, and the critical mass components must attain to be treated as Elements must be clearly established. The commenter requests confirmation that the statement "loss of significant number of units" in section 4.2.3. means "more than 75 MVA of aggregated capacity."

First, the SDT developed the "Target Applicability" categories to provide additional clarity on how the SDT believes the various standards listed in the White Paper Appendix B should be applied to DGR facilities based on the technical analyses performed by the SDT. The SDT recognizes the value of clear definitions of these four application types. However, the SDT does not intend to use specific terminology for these applications in the standard language modifications the SDT may develop and propose for these applications used in Appendix B, i.e., the point where aggregates to greater than 75 MVA, Point of Common Control, etc., and as such will not be proposing to add any of these definitions to the NERC Glossary. The SDT recognizes that any proposed standard language changes must provide clear guidance on applicability superior to the terminology used in Appendix B's "Target Applicability," so the SDT is therefore reviewing the White Paper and appendices to clarify the terms in question. The SDT will consider use of the term "Point of Interconnection" as applicable, at least to the extent it is consistent with SDT intent and industry consensus.

Second, the SDT confirms that the aggregated facilities refer to aggregate nameplate capability greater than 75 MVA and will clarify the White Paper to enhance the current explanation.

Finally, The SDT will review the White Paper and appendices to provide expanded explanation of the terms used. In section 4.2.3 of the White Paper the SDT intends to include individual generating units and the associated aggregating equipment in the applicability of certain requirements in order to account for cases in which common mode issues could impact reliability. In these cases, consideration of individual generating units and the associated aggregation equipment may be required at locations below the 75 MVA threshold, when common mode issues could affect greater than 75 MVA.

E. SDT Coordination

Some commenters note that active SDTs that are developing standards that require applicability changes should make those changes. Other commenters believe other SDTs may appropriately make applicability changes but question how gaps can be addressed as various standards versions are approved. For example, one commenter questions whether the SDTs for Projects 2007-06 and 2014-03 will finish in time so that entities' compliance is not affected.

The DGR SDT cannot answer or make predictions on the completion, passage, and approval of standards. However, the SDT is working as quickly as possible to address the identified standard modifications and is working with NERC to develop guidance to the Regions to account for any regulatory gaps in approving applicability changes to the standards. Moreover, the SDT is actively coordinating with other SDTs on those applicable standards for which current SDT work is underway and has posted a coordination document on the project web page to fully explain that coordination. Scope changes will be addressed with the SC as needed.

2. Identification of Standards Requiring Applicability Changes or Additional Guidance

The White Paper identifies 24 standards that may require modifications or guidance to account for the unique characteristics of dispersed power producing resources, including three high-priority standards. Industry was asked whether the SDT has correctly identified the standards that require applicability changes or additional guidance for DGRs. Industry generally agrees that the SDT has correctly identified the standards that require applicability changes or additional guidance, including the initial high-priority standards. However, some commenters expressed concerns and disagreements, or requested clarification on the SDT's recommendations, as follows:

At least one commenter questions why the SDT is focusing on multiple versions of the same standard, for example, PRC-005-1.1b and PRC-005-2, instead of focusing on either the currently effective standard or the standard under active development. The SDT must review all current and future versions of each standard requiring applicability changes or guidance to ensure that the appropriate applicability to DGR facilities is applied both currently and for any future versions.

At least one commenter believes the SDT has not made clear what six standards it is referring to on guidance, and notes that within Appendix B there are six standards with the Target Applicability of either "Point where aggregates to > 75 MVA" or "Individual BES Resources / Elements." The six standards referenced in the question are those where guidance may be sufficient to account for the unique characteristics of DGRs, which are identified as Guidance in column C (titled "Area To Change") of Appendix B and specifically are: FAC-008-3, PRC-019-1, PRC-024-1, PRC-025-1, MOD-025-2, and MOD-032-1.

3. Methodology for White Paper Recommendations

The White Paper describes how the SDT recommends addressing DGRs through changes to the applicability section, guidance documentation, or in the applicability of requirements. Industry was asked whether the SDT has correctly identified the best approach for each standard, and the methodology used to prioritize high-, medium-, and low-priority standards. Industry also was asked whether the SDT has correctly prioritized the standards. Industry generally agrees conceptually with the SDT's overall approach to addressing DGRs through changes to the applicability section, guidance documentation, or in the applicability of requirements, particularly the high-priority standards, and with the DGR's prioritization methodology. However, some commenters expressed concerns and disagreements, or requested clarification on the SDT's recommendations, as further discussed below.

One commenter argues that although Inclusion I4 refers to dispersed power resources that are “greater than 75 MVA to a common point of connection at a voltage of 100 kV or above,” for comparability to traditional resources (Inclusion I2), changes in standard thresholds for dispersed resources should apply to points where dispersed resources aggregate to greater than 20 MVA at a common point. The commenter urges the SDT to reconsider and adopt a consistent point where generation aggregates to greater than 20 MVA approach in each of these standards except VAR-002, and that if a 20 MVA threshold applies to I2 generators and that is reliability-based, there would be a reliability gap if a greater than 75 MVA threshold was adopted.

In order to provide consistent requirements for all generation, the SDT believes it is necessary to assess applicability on individual units greater than 20 MVA and aggregate generation greater than 75 MVA, which are thresholds that have been explicitly recognized and approved by FERC as an appropriate threshold for these types of facilities consistent with the revised BES definition.[1] The SDT therefore does not believe it would be appropriate to use different aggregation thresholds absent a robust technical justification to do so. Commenters have not provided a sufficiently compelling technical justification for any other aggregation thresholds, and industry consensus supports what the SDT has proposed. Therefore, the SDT respectfully declines to change the aggregation thresholds identified in the White Paper.

According to at least one commenter, section 4.2.2 of the White Paper notes that the age of DGRs affects their ability to provide reliability services, but that identification of relevant standards as described in the Technical Discussion does not refer to age or ability. It is not clear to the commenter what role those characteristics play in identifying relevant Standards. The SDT has identified and evaluated the applicability of relevant standards primarily with regards to how the reliability of the BES may be affected as a result of applying the requirements of each standard to DGR facilities. The SDT acknowledges that there are certain limitations in the capabilities of some older DGRs due to their age and technology; however, these limitations were not a primary consideration when identifying relevant standards to be addressed.

At least one commenter does not understand why the high-priority states: “High priority was assigned if compliance-related efforts with no appreciable reliability benefit would require not only significant resources but also would require efforts to be initiated by an entity well in advance of the implementation date.” The commenter believes that high priority should have the strongest reliability benefit, not “with no appreciable reliability benefit.” The commenter does agree with the high, medium, and low priority prioritization methodology. The SDT notes that the referenced statement may have been misinterpreted. The following restatement may help. High priority was assigned so that standard or requirement changes would be made

[1] *See* FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000.

quickly enough to avoid an entity having to expend inordinate resources prematurely to comply with a standard or requirement that, after appropriate DGR modification, would not be applicable to that entity.

At least one commenter expresses concern that the White Paper is unclear as to "how" it will attempt to implement changes, i.e., the process it will follow. The commenter recommends a new column in Appendix B that addresses the "how." The SDT agrees that this may be a good suggestion and will consider the appendix modification as suggested.

4. DGR Recommendation to Revise High-Priority Standards

The SDT recommends revising relevant versions of PRC-004, PRC-005, and VAR-002 as high-priority standards. Industry generally agrees that the SDT has correctly identified the high-priority standards that require immediate revision or guidance to account for DGRs. However, some commenters expressed concerns and disagreements, or requested clarification on the SDT's recommendations, as follows:

F. PRC-004

At least one commenter notes that the applicability of PRC-001, PRC-004, and PRC-005 should be congruent. The SDT intends to address standards similarly where practicable, but in many instances the format of revisions will need to be specific to the standard.

i. Misoperations Reporting for Common Mode Failures

The SDT believes it is not necessary under PRC-004 to analyze protection system Misoperations affecting individual dispersed generating units but is concerned with the potential for unreported Misoperations involving a common mode trip of several generating units. The SDT proposes requiring analysis for potential Misoperation of individual generating units; for example if a trip of greater than 75 MVA nameplate aggregate occurs in response to a system disturbance. The SDT selected the 75 MVA nameplate threshold for consistency and to prevent confusion. As one commenter notes, it is widely agreed that until capability aggregates to that level, BES reliability is not threatened. Industry consensus supports this approach, but some commenters expressed concerns and disagreements, as further discussed in this subsection.

Several commenters express concern that the SDT intends to exclude from PRC-004 dispersed power producing resources, noting, for example, that it is important to know about relay Misoperations in order to maintain system reliability. This extends to individual units that make up an aggregated dispersed power producing resource, especially when one considers the potential that similar practices would be used in setting each of the protection systems applied to individual units.

The SDT agrees that it is important to know about certain relay Misoperations in order to maintain system reliability. The SDT considered all comments related to Misoperations and wishes to clarify that the applicability of the revised Standard would include cases for which the root cause of the Protection System operation(s) *did or could have affected* an aggregate nameplate rating of greater than 75 MVA of BES Facilities. The SDT also maintains that 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 large number of the individual generation resources (aggregate nameplate rating of greater than 75 MVA) incorrectly operated or failed to operate as designed during a system event. The SDT also is considering the applicability of events where one or more individual units tripped and the root cause of the operations were identified as a setting error – in these cases, PRC-004 would be applicable if identical settings are applied on Protection Systems for like individual units in the facility with aggregate nameplate rating of greater than 75MVA. Industry consensus supports the SDT's direction on Misoperations, and the SDT will clarify the White Paper to more accurately reflect SDT intent.

ii. Aggregation Threshold for Misoperations Reporting

Several commenters note that PRC-004's applicability should be limited to individual protection system components that affect greater than 75 MVA of capability. The SDT agrees it is important to be proactive and assess any Misoperations that could result in a loss of greater than 75 MVA of nameplate generation. This includes Misoperations of Protection Systems that are applied on the individual power producing resources in cases for which the root cause of the Protection System operation(s) did or could have affected an aggregate nameplate rating of greater than 75MVA of BES Facilities. For example, if one or more individual units tripped and the root cause of the operations was identified as a setting error, then PRC-004 would be applicable if identical settings are applied on Protection Systems for like individual units in the facility with aggregate nameplate rating of greater than 75 MVA.

Some commenters believe the aggregate threshold should be lower than 75 MVA, with at least one commenter suggesting a 20 MVA threshold. One commenter notes that if a 20 MVA threshold applies to I2 generators and that is reliability-based, there would be a reliability gap if a greater than 75 MVA threshold was adopted. In order to provide consistent requirements for all generation, it is necessary to assess applicability on individual units greater than 20 MVA and aggregate generation greater than 75 MVA, thresholds that have been accepted by FERC in the context of the BES definition approval. Since commenters have not provided a technically justified alternative supported by industry consensus, it would not be appropriate to use different aggregation thresholds. Therefore, in the context of PRC-004, it is necessary to assess potential reliability impact on the operation of the interconnected transmission network when Misoperations may result in a loss of greater than 75 MVA of capacity to the BES. This rationale is consistent with the rationale for including in the BES the portion of the collector system that aggregates greater than 75 MVA of dispersed power producing resources.

Some commenters argue that for the vast majority of dispersed generating resources a common mode failure for that dispersed generating resource site would not impact reliability in most cases. One commenter notes that most of these sites are not that large, and because the output is variable, these resources must be backed up with operating reserve to account for their variability. The commenter also argues that there are other NERC standards that require operation of the BES to withstand the next contingency so the loss of entire wind farm or solar array will not be impactful to reliability unless another standard is concurrently violated. The SDT asserts that Misoperations of Protection Systems on a large number of individual resources can have an impact upon BES reliability when the aggregate nameplate capacity of those resources associated with the Misoperation is in excess of an aggregated nameplate rating of 75 MVA, especially in consideration of the N-1, N-2 scenarios in which multiple facilities experience these Misoperations. This rationale is consistent with the rationale for including in the BES the portion of the collector system that aggregates greater than 75 MVA of dispersed power producing resources, and also is supported by industry consensus.

The SDT also notes that it proposes that the protection systems associated with the individual generating resources that contribute to the 75 MVA nameplate rating threshold would become in scope, in regards to PRC-004, when misoperation of Protection Systems on the individual resources is the cause of reaching the threshold.

iii. Other Comments

At least one commenter does not support any language that would effectively bring turbine control systems in scope for PRC-004 in lieu of protection systems, which is the current scope of PRC-004. The SDT does not intend to include turbine control systems in the scope of PRC-004 and will clarify this in the rationale for proposed changes to PRC-004.

G. PRC-005

Some commenters believe that relay maintenance is a vital part of system reliability, and that reducing the applicability of the standard seems counter to good utility practice. The SDT asserts that relay maintenance on individual units would not provide a significant reliability benefit to the BES and therefore should remain at the discretion of the entity as opposed to a

NERC-enforced requirement. Industry consensus supports the SDT's position, so it will therefore decline to adopt the commenters' position.

Other commenters voice agreement and disagreement with the proposed 75 MVA aggregation threshold, which the SDT addressed above in response to PRC-004 comments. The SDT proposes that the scope of PRC-005 be limited to include only the protection systems that operate at a point of aggregation above 75 MVA nameplate rating. If the aggregation point occurs at a component in the collection system, then the protection systems associated with this component would be in scope. This will be clearly addressed in the standard revisions.

Please note that the SDT recognizes that PRC-005-1.1b will be phased out beginning in early 2015. Therefore, the SDT is focusing solely on PRC-005-2 and future versions of PRC-005, and recommends only guidance on PRC-005-1.1b rather than suggesting language changes to the standard. The SDT is working with NERC staff to ensure the appropriate guidance is provided.

H. VAR-002

The SDT notes that question 10 in the request for comments form was misstated, and should have been: "With respect to VAR-002-2b, does the NERC DGR SDT need to provide guidance to ensure dispersed power producing resources individual generator transformers are not subject to the R4 and R5, as they are not used to improve voltage performance at the point of interconnection?"

i. Target Applicability Specific to VAR-002

Some commenters believe the VAR-002 target applicability should be at the point of interconnection. Another commenter suggests that the SDT needs to provide less guidance whereby the GO/GOP can develop their own way of meeting the TOP's voltage schedule, as the SDT should not be so granular to discuss items that are on the collector system, which is not a BES asset. The SDT was careful to consider all target applicability options in assessing all of the potential applicability changes, including VAR-002. In the absence of industry consensus supporting the contrary, the SDT respectfully declines to change its recommendation on the appropriate DGR applicability in VAR-002.

ii. Requirements R3, R4, and R5

Some commenters do not support a blanket exclusion of dispersed power producing resources from Requirements R4 and R5. Commenters believe that information under Requirement R4 has to be provided only upon request of the Transmission Planner and Transmission Operator, and if this information is not necessary, it should not be requested. Similarly, according to commenters, Requirement R5 is only applicable if the Transmission Operator requests a change to the tap setting, and the Transmission Operator should only do this when necessary; therefore, there is no need to modify the applicability of the standard. Another commenter notes that if the individual generator transformers are below the BES defined level then R4 and R5 should not apply.

At least one commenter argues that the individual generator transformers within the DGR can be excluded in Requirements R4 and R5 in favor of the main aggregating transformer connected to the BES, and that revised applicability should also be included in Requirement R3. The commenter notes that there can be power factor correction capacitors located within each individual generator transformer, and only major sources of Reactive Power that impact the BES should be included in the applicability of Requirement R3.

At least one commenter believes that in general, providing voltage regulation at the point of aggregation is acceptable, but that embedded dynamic devices may affect aggregate voltage performance. The commenter notes that "clarification" needs to address this.

The SDT agrees that a GOP's voltage controlling equipment Elements differs based on the type of generation facility. Each generation facility may have a different methodology to ensure the facility has an automatic and dynamic response to changes in voltage, to ensure the TOP's instructions are maintained. It is implied in NERC VAR-001-3 that each GOP and TOP should understand capabilities of the generation facility and the requirements of the transmission system to ensure a mutually agreeable solution/schedule is used. The SDT also believes that pursuant to the NERC Bulk Electric System Definition Reference Document, Version 2, dated April 2014, individual generator transformers are included in the BES. As such, applicability revisions to the standard are required to ensure appropriate application to DGRs as outlined in the White Paper.

iii. Dynamic and Reactive Devices

At least one commenter states that DGRs are often required to install reactive devices as a condition of interconnection. A commenter believes the applicability of VAR-002 should specify how these devices should be treated when establishing voltage schedules and performance expectations, and that if dispersed generation is to include storage devices, care should be taken that requirements are technology neutral. Another commenter states that other reactive devices, such as embedded dynamic reactive devices, may affect aggregate voltage performance and should be addressed.

The SDT agrees with commenters that a GOP's voltage controlling equipment and Elements differ based on the type of generation facility. Each generation facility may have a different methodology to ensure the facility has an automatic and dynamic response to changes in voltage, to ensure the voltage schedule is maintained. It is implied in NERC VAR-001-3 that each GOP and TOP should understand capabilities of the generation facility and the requirements of the transmission system to ensure a mutually agreeable solution and schedule is used.

One commenter believes that the standards should apply only to DGRs that are designed to provide voltage and reactive support for the BES, which includes those where voltage or reactive sources (cap banks, reactor banks, static var devices, plant voltage outer-loop control, etc.) which are installed specifically to provide system voltage and reactive support at the point of interconnection or aggregate facility level. The commenter believes that DGRs that do not have such capability by design should be exempted from VAR-002-2b. The SDT disagrees because each generation facility may have a different methodology to ensure the facility has an automatic and dynamic response to changes in voltage, to ensure the voltage schedule is maintained. It is implied in NERC VAR-001-3 that each GOP and TOP should understand capabilities of the generation facility and the requirements of the transmission system to ensure a mutually agreeable solution/schedule is used. In the absence of industry consensus to the contrary, the SDT respectfully declines to adopt the commenter’s suggestion.

5. DGR Recommendation to Revise or Provide Guidance on Medium- and Low-Priority Standards

The White Paper identifies several medium- and low-priority standards where applicability revisions are required, or where guidance may be most appropriate to account for the unique characteristics of DGRs. Industry was asked whether the SDT has correctly identified the standards that require modification or additional guidance for DGRs. Industry generally agrees that the SDT has correctly identified the standards where additional guidance is most appropriate. However, some commenters expressed concerns and disagreements, or requested clarification on the SDT’s recommendations, as follows:

At least one commenter suggests that the SDT should be as precise as possible in the guidance it provides, since that guidance will be the basis for significant revisions to the numerous standards identified to date. The SDT agrees and intends to do so.

A. MOD

At least one commenter suggests that the SDT correctly identifies some standards, such as the MOD standards, where “the SDT will consider the need to develop guidelines for dispersed generation resource modeling and therefore recommends consulting other groups” that are currently working on these issues, which is inconsistent with the statement in the same section “The existing and proposed modeling standards are sufficient for modeling dispersed generation resources." As such, the commenter suggests, it is suggested that the SDT may wish to consult with these groups prior to establishing priorities on some standards. Based on industry consensus on this issue, the SDT believes that the current and upcoming modeling standards are sufficient to address DGR facilities. However, guidance will be provided for this standard with recommendations from other standard development teams and NERC workgroups, and the White Paper will be updated to reflect the SDT's revised recommendation.

At least one commenter believes that the target applicability for MOD-032 should be on the aggregate facility level. Modeling will be required at both the aggregate and unit level in accordance with BES inclusion I4 consistent with modeling of other multiple unit stations.

Some commenters believe it is important that generators provide accurate models of each individual unit, and that if all units are identical, then providing aggregate information may be sufficient. Commenters noted, however, if units are not identical, then generators should be required to provide individual models.

With respect to MOD-32, the SDT and NERC intend to provide guidance on how to best model DGR facilities. Such guidance should require modeling requirements for each type of DGR within a facility and aggregate model for each reasonable aggregation point. The SDT will update the White Paper to reflect that recommendation.

B. PRC-006

At least one commenter notes that although there was discussion of the NPCC and SERC versions of PRC-006-1, the commenter did not see any discussion regarding the NERC version of PRC-006 in the White Paper, which needs to be included. The commenter is concerned about the coordination of some changes with other drafting teams identified for several requirements in the whitepaper. The SDT focused its initial review on standards applicable to GOs and GOPs. PRC-006 is not applicable to either entity. With regard to PRC-006 requiring modeling and coordination, the generation thresholds in PRC-006-1 are applicable to any generation, regardless of type. As explained above, the SDT and NERC are heavily engaged in coordinating with SDTs developing corresponding standards.

C. PRC-024

At least one commenter believes that PRC-024 needs to pertain to common settings for individual generating resources where incorrectly set protection elements could cause greater than 75 MVA to trip where is it not desired. The SDT asserts that PRC-024-1 should apply at the individual resource level. It is necessary that the protection settings on each individual turbine meet the requirements in PRC-024 to avoid the potential for a common mode trip of generation in response to a frequency and/or voltage disturbance. Scenarios in which a large number of individual resources (i.e., greater than 75 MVA aggregate nameplate rating) experience a trip in response to a system disturbance could adversely impact reliability of the BES.

One commenter notes that section 5.10.4 relates applicability of PRC-004 to PRC-024 but is not clear what is proposed to be changed in PRC-004. The SDT proposes to include individual resources in the scope of PRC-004 only when the associated protection systems experienced a misoperation that affected or could have affected an aggregate nameplate rating of greater than 75 MVA during a “common-mode failure” type scenario. The reference to PRC-024 was solely meant to convey that similar scenarios would be considered for PRC-024.

One commenter notes that the SDT has determined it is necessary to require that Protection Systems applied on both the individual generating units, as well as any aggregating facilities, are set within the “no-trip zone” referenced in the requirements to maintain reliability of the BPS. The commenter also notes that the SDT says no changes to applicability are required, but states an RSAW or guidance should specify compliance evidence requirements. The SDT asserts that the requirements currently listed in PRC-024 are appropriate to apply to dispersed power producing resources and their associated aggregating Facilities, and therefore is recommending no changes. The SDT is not attempting to infer that compliance requirements can be specified in an RSAW, however RSAWs can establish what compliance related evidence should be utilized for auditing purposes. The SDT recognizes that for the purposes of providing this compliance related evidence, it should be sufficient for an entity to provide evidence for a single sample generating unit within a site as these units are typically set identically, rather than providing documentation for each individual unit. As such the SDT recommends the RSAW be modified as stated above.

D. PRC-025

At least one commenter does not understand why PRC-025 would need to apply to individual generating units in a dispersed generator resource, which would imply that the loss of a single unit at these dispersed generation resource sites would have a reliability impact which would be counterintuitive to this entire standards project. Furthermore, the commenter argues, it is not consistent with the drafting team’s approach that standards that apply to individual generating elements need to be modified. The commenter believes that the White Paper may even contradict the applicability section 3.2.5 of the standard that states “Elements utilized in the aggregation of dispersed power producing resources,” which suggests the standard applies to individual generating elements and not the GOP as a whole. The commenter suggests that either PRC-025 should be added to the standards that need the applicability modified or a better explanation for why it does not need to be modified should be provided in the White Paper.

The SDT does not intend to imply that the loss of a single generating unit at a dispersed generating facility would have a significant reliability impact on the BES. However, the SDT asserts that in scenarios in which a large number of individual resources (i.e., greater than 75 MVA aggregate nameplate rating) experience a trip in response to a system disturbance, there could be an adverse impact to reliability of the BES. This scenario could occur if the load-responsive protective relay in each generating unit were not set as required by PRC-025. Regarding 3.2.5 of the applicability section in PRC-025, the SDT believes that the inclusion of the aggregating equipment in the requirements in this standard does not preclude the need to also apply the requirements to the individual generating resources.

E. TOP-001

At least one commenter argues that TOP-001 applies to all entities registered as GOP, and that there is no defined reporting threshold in the standard. The commenter believes that the recently filed but remanded TOP standards allowed the TOP to determine its data reporting requirements and that PJM requires its intermittent resources to report any change to real power that is equal to or exceeds one MW. For this reason, the commenter does not agree with the SDT relative to this requirement and similar requirements. Based on the PJM Manual 14D, §8.2.4. "…wind resources shall report any outage of one megawatt or more with duration of one hour or longer. Outages shall be submitted on aggregate plant capacity by outage type," the SDT agrees with the commenter that there is no defined threshold for coordination in TOP-001-1a, and PJM requires wind resources to coordinate changes in aggregate plant capacity of greater than one MW for more than one hour. Therefore, the SDT will take commenter's suggestions into consideration prior to posting and balloting any changes to TOP-001-1a.

Another commenter disagrees with the determination for TOP-001-1a Requirement R6 in the White Paper because actions therein would be issued via a directive and are covered under IRO-001-1.1 R8 and TOP-001-1a R3 directive. Thus, according to the commenter, the requirement does not need to apply to DGRs. The commenter further suggests that for TOP-003-1 Requirement R1, the White Paper should explain that the standard should be applied on an aggregate basis and not an individual resource basis, and that there is no need for the Transmission Operator to be aware of individual wind turbine outages, as they only need to know the aggregate outage amount.

The SDT does not agree that TOP-001-1a Requirement R6 should not be applicable to DGRs. There can be a plethora of scenarios in which a DGR could be called on to provide emergency assistance, including the examples provided by the commenter. In addition, another scenario could be voltage support. It should be noted that TOP-001-1a Requirement R6 uses the term 'requested' and not 'directed', which differentiates it from IRO-001-1.1 Requirement R8 and TOP-001-1a Requirement R3. Further, pursuant to IRO-001-1.1 Requirement R8 and TOP-001-1a

Requirement R3, Generator Operators are only required to comply with Reliability Directives issued by the Reliability Coordinator and Transmission Operator, which implies the Reliability Coordinator and Transmission Operator are the only functional entities that can issue a Reliability Directive. TOP-001-1a Requirement R6 allows for any user of the BES to request emergency assistance from others so long as they have implemented comparable emergency procedures. If the SDT were to limit applicability here, a reliability gap may be created by limiting the extent an entity must provide emergency assistance.

F. TOP-003

One commenter believes for TOP-003-1 Requirement R1, the White Paper should explain that the standard should be applied on an aggregate basis and not an individual resource basis. There is no need for the Transmission Operator to be aware of individual wind turbine outages. They only need to know the aggregate outage amount. The purpose of TOP-003-1 Requirement R1 as it relates to GOPs is to ensure TOPs are provided planned outage information on daily basis for any scheduled generator outage greater than 50 MW for the next day. The SDT is unaware of any single wind turbine generator that has at least a 50 MW name plate rating. Therefore, the SDT respectfully declines to adopt the commenter's suggestion.

6. Standards Not Identified as Requiring Applicability Changes or Guidance

Several commenters suggest that the SDT should consider standards and requirements not identified in the White Paper Appendix B for additional guidance or applicability changes. For example, at least one commenter notes that the SDT should review the standards from the perspective of whether a GO/GOP has only dispersed generation resources and no other resources.

The SDT notes that in preparation for the initial posting it has focused primarily on finalizing applicability recommendations on the high-priority standards identified in the White Paper, and has intended to focus on the medium- and low-priority standards after its recommendations on the high-priority standards are posted for comment. Now that the initial posting on some high-priority standards has occurred, the SDT will further consider the comments noted in this section as it reviews medium- and low-priority standards as identified in the White Paper, and will revise its recommendations if supported by sound technical bases and industry consensus.

A. CIP

One commenter believes that the CIP standards must be modified to remove the individual dispersed generator controls from the scope, and references its understanding of the direction in FERC Order 791 to develop actual auditable requirements for low impact BES Cyber Systems.

The SDT intends to recommend guidance for those companies that only operate their turbines from one central location. Individual elements lumped into a BES Cyber System should be addressed. When operations are on a turbine-by-turbine basis, the SDT believes there should not be rigid controls in place. The inability to "swim upstream" should be addressed as well. Further, the guidance intends to address when manufacturers operate or have control of the SCADA environment to conduct troubleshooting and other tasks, and ensure that proper security is in place. The CIP SDT and DGR SDT will coordinate in the next few weeks to develop language for the guidance. The CIP SDT can walk through the revisions to CIP-003-6 Requirement R2 and gather feedback from the DGR SDT to appropriately develop guidance.

As for the commenter's reference to FERC Order 791 in support of its belief that the CIP standards must be modified to remove the individual dispersed generator controls from the scope, it is unclear how that order should compel the SDT to act contrary to its own technical expertise the technical expertise of the CIP SDT and clear industry consensus to cause a modification to the CIP standards to account for DGRs. However, the DGR SDT will continue to defer to and coordinate with the CIP SDT to provide further guidance as to what should occur to account for DGRs.

B. EOP

At least one commenter notes that although EOP-004-2 appears to apply to the function and not the individual elements, closer inspection reveals that a GO with DGRs would have to report for each individual unit as the dispersed generation site when there is damage or destruction of its facility that results from actual or suspected intentional human action. The commenter also notes that if EOP-005-2 is reviewed from the perspective of applying the standard to a GOP that only operates DGRs, the commenter questions if the standard should apply at all. A commenter also notes that the definition of Facility would include individual wind turbines since they are classified as part of the BES, which means that if there was intentional damage caused to 1 MVA wind turbine at an applicable dispersed generation resource site, the BA, GO, and GOP would all have to report intentional human damage per EOP-004-2. A commenter believes there are other thresholds for reporting that would apply in EOP-004-2 as well, which need to be reviewed further.

At least one commenter believes that if EOP-005-2 is reviewed from the perspective of applying the standard to a GOP that only operates DGRs, the commenter questions if the standard should apply at all. The commenter notes that if DGRs cannot serve as Blackstart Resources, only one requirement (R18) would apply and the GOP would be burdened with proving that the Blackstart Resource requirements do not apply during every compliance monitoring event. Furthermore, the commenter questions the role a GOP with only DGRs could play in restoration. The commenter questions if they have no role, why would they need to participate in restoration drills, exercises, or simulations.

As noted above, the SDT will consider these comments as it further reviews medium- and low-priority standards as identified in the White Paper.

C. FAC

At least one commenter suggests that the SDT consider modifying FAC-001-1. For example, one commenter notes that the scope of the standard should be clear that any special connection requirements for dispersed power producing resources (Inclusion I4) should be documented. The SDT will consider this suggestion as it continues to analyze recommended actions on this standard.

Some commenters disagree that issues with FAC-008-3 can be addressed with guidance alone, but other commenters agree. One commenter agrees with the SAR recommendations that the applicability of FAC-008 be limited to the point of 75 MVA or above. Furthermore, one commenter believes the wording of Requirements R1 and R2 is very problematic due to the uncertainty caused by the usage of the term "main step up transformer" as well as the wide variability in the possible location of "the point of interconnection with the Transmission Owner." One commenter recommends simplifying FAC-008-3 R1 and R2 to state that: "The Generator Owner must have a ratings methodology and study for the following: For BES generation not included per BES Definition Inclusion I4, from and including the generator to the point of interconnection to the Transmission Owner system. For BES generation included per BES Definition Inclusion I4, for all Generator Owner owned equipment from the point of aggregation of 75 MVA or greater to the point of interconnection to the Transmission Owner system."

The use of the term main-step-up transformer in R1 and R2 refers to the final GSU, i.e., the last transformer used exclusively for stepping up the generator output prior to the Point of interconnection or, when the POI is before the GSU, the GSU that steps up voltage to transmission line voltage level, and is utilized strictly as a delineation point between R1 and R2. A GO is responsible for determining and documenting facility ratings for the equipment that it owns up to the main step-up transformer, in accordance with R1, as well as all of the equipment it owns from the main step-up transformer to the point of interconnection, in accordance with R2, when the dispersed generation resource facility generation is equal to or greater than 75 MVA. Therefore, guidance may be appropriate to identify the main step-up transformer for a DGR facility.

Facility ratings are required for all elements/components that serve to generate and/or deliver generated electricity to the grid and must include non-BES electrical elements. This is necessary to provide an accurate representation of the facility capabilities which are used in modeling and planning activities. The SDT intends to adopt the existing scope of FAC-008 requirements, for dispersed power producing resources, as the required rating information is an integral part of establishing accurate modeling and facilitating planning operations. Therefore the SDT respectfully declines to adopt the commenter's suggestion of proposed FAC-008 modifications, which would exclude equipment below the 75 MVA aggregation point.

D. NUC

One commenter disagreed with the SDT position that limiting the applicability of the NUC standard to exclude dispersed generation resources would create a reliability gap, stating that a Nuclear Plant Generator Operator cannot practically rely on variable output resources such as dispersed generation resources to meet its NPIRs. Thus, according to the commenter, limiting applicability does not create reliability gap. Absent industry consensus or other compelling reliability justification to support this commenter's view, the SDT respectfully declines to adopt it.

E. VAR

At least one commenter suggests that the SDT should consider modifications to VAR-001-3 to include language more appropriate for DGRs. The SDT will consider these comments as it further reviews medium- and low-priority standards as identified in the White Paper.

7. Other Comments

Most additional comments make suggestions to improve and clarify the White Paper, which the SDT will consider and incorporate where consistent with SDT intent and industry consensus. Some responses to these comments have been included above.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you may contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[2]

[2] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

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

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Randi Heise	Dominion NERC Compliance Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion	SERC	5, 6
2.	Connie Lowe	Dominion	RFC	5, 6
3.	Mike Garton	Dominion	NPCC	5
4.	Larry Nash	Dominion	SERC	1, 3
5.	Randi Heise	Dominion	NPCC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Sandra Shaffer	PacifiCorp						X				

No Additional Responses

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliaibility Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
4. Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC 1										
5. Wayne Sipperly	New York Power Authority	NPCC 5										
6. Gerry Dunbar	Northeast Power Coordinating Council	NPCC 10										
7. Mike Garton	Dominion Resources Services, Inc.	NPCC 5										
8. Matt Goldberg	ISO - New England	NPCC 2										
9. Michael Jones	National Grid	NPCC 1										
10. Mark Kenny	Northeast Utilities	NPCC 1										
11. Christina Koncz	PSEG Power LLC	NPCC 5										
12. Helen Lainis	Independent Electricity System Operator	NPCC 2										
13. Ben Wu	Orange and Rockland Utilities Inc.	NPCC 3, 1										
14. Alan MacNaughton	New Brunswick Power Corporation	NPCC 9										
15. Bruce Metruck	New York Power Authority	NPCC 6										
16. Brian Shanahan	National Grid	NPCC										
17. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10										
18. Robert Pellegrini	The United Illuminating Company	NPCC 1										
19. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC 1										
20. David Ramkalawan	Ontario Power Generation, Inc.	NPCC 5										
21. Brian Robinson	Utility Services	NPCC 8										
22. Ayesha Sabouba	Hydro One Networks Inc.	NPCC 1										
4. Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				
Additional Member	**Additional Organization**	**Region / Segment Selection**										
1. Alice Ireland	Xcel Energy	MRO 1, 3, 5, 6										
2. Chuck Wicklund	Otter Tail Power	MRO 1, 3, 5										
3. Dan Inman	Minnkota Power Coop	MRO 1, 3, 5, 6										
4. Dave Rudolph	Basin Electric Power Coop	MRO 1, 3, 5, 6										
5. Kayleigh Wilkerson	Lincoln Electric System	MRO 1, 3, 5, 6										
6. Jodi Jensen	WAPA	MRO 1, 6										
7. Joseph DePoorter	Madision Gas & Electric	MRO 3, 4, 5, 6										
8. Ken Goldsmith	Alliant Energy	MRO 4										
9. Mahmood Safi	Omaha Public Power District	MRO 1, 3, 5, 6										
10. Marie Knox	MISO	MRO 2										
11. Mike Brytowski	Great River Energy	MRO 1, 3, 5, 6										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Bos	Muscatine Power & Water	MRO	1, 3, 5, 6
14.	Scott Nickels	Rochester Public Utilities	MRO	4
15.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
16.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
17.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.		Louisville Gas and Electric Company and Kentucky Utilities Company	SERC	3
2.	1.	PPL Electric Utilities Corporation	RFC	1
3.	2.	PPL Generation, LLC	RFC	5
4.	3.	PPL Susquehanna, LLC	RFC	5
5.	4.	PPL Montana, LLC	WECC	5
6.		PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Cindy Stewart	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William J Smith	FirstEnergy Corp	RFC	1
2.	Douglas G Hohlbaugh	Ohio Edison	RFC	4
3.	Kenneth J Dresner	FirstEnergy Solutions	RFC	5
4.	Kevin J Querry	FirstEnergy Solutions	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

2. Daniel Herring	NERC Training & Standards Development	RFC	4
3. Mark Stefaniak	Regulated Marketing	RFC	5
4. David Szulczewski	DO SEE Relay Engineering		

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Silvia Parada Mitchell	NEA Joint Commenters (NextEra, Exelon and MidAmercian)	X		X		X	X				

No Additional Responses

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Colby Bellville	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils	Duke Energy	RFC	1
2. Lee Schuster	Duke Energy	FRCC	3
3. Dale Goodwine	Duke Energy	SERC	5
4. Greg Cecil	Duke Energy	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

Additional Member	Additional Organization	Region	Segment Selection
1. John Allen	City of Springfield	SPP	1, 4
2. J.Scott Williams	City of Springfield	SPP	1, 4
3. James Nail	City of Independence Missouri	SPP	3
4. Stephanie Johnson	Westar	SPP	1, 3, 5, 6
5. Bo Jones	Westar	SPP	1, 3, 5, 6
6. Tiffany Lake	Westar	SPP	1, 3, 5, 6
7. Wes Mizell	Westar	SPP	1, 3, 5, 6
8. Robert Rhodes	Southwest Power Pool	SPP	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				

No Additional Responses

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Jason Marshall	ACES Standards Collaborators						X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
2.	Scott Brame	NCEMC	SERC	
3.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1
4.	Bob Solomon	Hoosier Energy	RFC	1

13.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
14.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
15.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
16.	Individual	Tim Brown	Idaho Power Company	X									
17.	Individual	Barbara Kedrowski	Wisconsin Electric Power Co			X	X	X					
18.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
19.	Individual	John Pearson	ISO New England		X								
20.	Individual	Heather Bowden	EDP Renewables North America LLC					X					
21.	Individual	Scott Langston	City of Tallahassee	X									
22.	Individual	Bill Fowler	City of Tallahassee, TAL			X							
23.	Individual	Karen Webb	City of Tallahassee - Electric Utility					X					
24.	Individual	Larry Heckert	Alliant Energy				X						

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Agree	Supporting Comments of "Entity Name"
N\A	N\A	N\A

1. **The posted white paper and its Appendix B identify 24 standards that may require modifications or guidance to account for the unique characteristics of dispersed power producing resources, including three high priority standards. Do you agree that the DGR SDT has correctly identified the standards that require applicability changes or additional guidance for dispersed power producing resources? If not, please explain.**

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 1 Comment
Dominion NERC Compliance Policy	No	Dominion does not agree from a technical perspective. The requirement applies to all entities registered as GOP. There is no defined reporting threshold in the standard. We think the recently filed (but remanded TOP standards) allowed the TOP to determine its data reporting requirements; and, Dominion knows for a fact that PJM requires its intermittent resources to report any change to real power that is equal to, or exceeds, 1 mw. For this reason, we do not agree with the SDT relative to this requirement. Also disagree with 5.11.3.3 Requirement R14 for same reason.
Northeast Power Coordinating Council	No	PRC-004-2.1a should not be modified to exclude dispersed power producing resources. it is important to know about relay misoperations in order to maintain system reliability. This extends to individual units that make up an aggregated dispersed power producing resource, especially when one considers the potential that similar practices would be used in setting each of the protection systems applied to individual units . FERC has explicitly recognized this in its March 20, 2014 Order Approving Revised Definition, where it stated that: â€œ[f]or example, a wind farm larger than 75 MVA can affect reliability if all of its wind turbines trip offline simultaneously after just a slight fluctuation in voltage or frequency. Therefore, because variable generation can impact the interconnected transmission network, we anticipate that wind plant owners whose facilities meet the inclusion I4 criteria who seek to exclude individual wind turbines from the bulk electric

Organization	Yes or No	Question 1 Comment
		system through the exception process will be infrequent.â€� See North American Reliability Corporation, 146 FERC Â¶ 61,199 (2014) at P 48.
MRO NERC Standards Review Forum	No	Within Appendix B under column â€œTarget Applicabilityâ€� there are four (4) different applications; â€œPoint where aggregates to > 75 MVA, Individual BES Resources / Elements, Point of common control, and Aggregate Facility Level. Without these attributes being defined, the industry cannot know if the Standards within Appendix B have the proper â€œTarget Applicabilityâ€�. Recommend that these terms be included in the NERC Glossary of Terms as they will have a major impact on the applicability of the Standards with reference to dispersed power producing resources. The SDT is encouraged to proceed expeditiously on the identified high priority standards: PRC-004-2.1a, PRC-005 (relevant versions) and VAR-002 so that owners can proceed with implementation of the BES definition and these standards without unnecessary interim work.
NEA Joint Commenters (NextEra, Exelon and MidAmercian)	No	NextEra Energy, Inc., Exelon, and MidAmerican (Joint Commenters NEA) jointly submit these comments. The Joint Commenters NEA individually and collectively own and operate most of the variable generation in North America, and, therefore have unique perspective and expertise on the issues presented in the April 14, 2014 Draft White Paper Proposed Revisions to the Applicability of NERC Reliability Standards NERC Standards Applicability to Dispersed Generation Resources (Draft White Paper). The Joint Commenters NEA appreciates the hard work that is represented in the Draft White Paper, and the technical discussion of the Standards. The Joint Commenters NEA also appreciates the identification of three Standards that for technical reasons should be revised; however, the Joint Commenters NEA are concerned that the White Paper goes much further than the scope of the Standards Authorization Request and recommends that the drafting team focus its efforts solely on three identified Standards. Specifically, the Joint Commenters NEA supports the Standards Drafting Team (SDT) moving

Organization	Yes or No	Question 1 Comment
		forward with revisions to PRC-004-2.1a, PRC-005 (relevant versions) and VAR-002. The Joint Commenters NEA do not support the SDT moving forward on work of any other Standard, because there is not a clear and justified technical reason at this time to require revisions to any more Standards. Specifically, the Joint Commenters NEA recommend that the SDT hand off all other observations in the Draft White Paper to NERC Staff to work with the appropriate NERC technical committees to develop and publish any guidance, etc needed for those Standards.
ACES Standards Collaborators	No	(1) The drafting team has done an excellent job reviewing all of the standards that apply to GOs and GOPs and also identifying some of the ancillary issues such as the interaction of BAs, TOPs, and RCs and dispersed generation resources. However, we do believe a deeper dive is required with some of the standards to identify additional issues and that the standards need to be reviewed from the perspective of whether a GO/GOP has only dispersed generation resources and no other resources. Specific examples of our concerns are discussed below.(2) For example, while EOP-004-2 at first glance appears to apply to the function and not the individual elements, closer inspection reveals that a GO with dispersed generation would have to report for each individual unit as the dispersed generation site when there is â€œdamage or destruction of its Facilitiy that results from actual or suspected intentional human actionâ€. The definition of Facility would include individual wind turbines since they are classified as part of the BES. This literally means that if there was intentional damage caused to 1 MVA wind turbine at an applicable dispersed generation resource site, the BA, GO, and GOP would all have to report intentional human damage per EOP-004-2. There are other thresholds for reporting that would apply in EOP-004-2 as well. These need to be reviewed further.(3) If EOP-005-2 is reviewed from the perspective of applying the standard to a GOP that only operates dispersed generation resources, we question if the standard should apply at all. Can dispersed generation

Organization	Yes or No	Question 1 Comment
		resources be Blackstart Resources? If dispersed generation resources cannot serve as Blackstart Resources, only one requirement (R18) would apply and the GOP would be burdened with proving that the Blackstart Resource requirements do not apply during every compliance monitoring event. Furthermore, what possible role could a GOP with only dispersed generation resources play in restoration. If they have no role, why would they need to pariticpate in â€œrestoration drills, exercises, or simulationsâ€�. (4) We disagree that limiting the applicability of the NUC standard to exclude dispersed generation resources would create a reliability gap. A Nuclear Plant Generator Operator cannot practically rely on variable output resources such as dispersed generation resources to meet its NPIRs. Thus, limiting applicability does not create realibility gap. (5) We disagree with the determination for TOP-001-1a R6 in the whitepaper. The requirement requires the GOP to provide â€œall available emergency assistanceâ€�. From a reliability perspective, what â€œemergency assistanceâ€� would the GOP of a dispersed generating resource be expected to supply. Shut down the units or reduce output? These are examples of actions that would be issued via a directive and are covered under IRO-001-1.1 R8 and TOP-001-1a R3 directive. Thus, the requirement does not need to apply to dispersed generation resources.(6) For TOP-003-1 R1, the whitepaper should explain that the standard should be applied on an aggregate basis and not an individual resource basis. There is no need for the Transmission Operator to be aware of individual wind turbine outages. They only need to know the aggregate outage amount.
Public Service Enterprise Group	No	Although Inclusion I4 refers to dispersed power resources that are â€œgreater than 75 MVA to a common point of connection at a voltage of 100 kV or above,â€� for comparability to traditional resources (Inclusion I2), changes in standard thresholds for dispersed resources should apply to points where dispersed resources aggregate to greater than 20 MVA at a

Organization	Yes or No	Question 1 Comment
		common point. While these points may be considered non-BES, many standards apply to non-BES Elements, and the BES definition does not prohibit the application of standards to non-BES Elements. For example, Cranking Paths that are less than 100 kV are still subject to EOP-005-2. See Order 773, paragraph 103. In addition UFLS is not in the BES definition, but standards still apply â€“ see PRC-006-2.â€¢ We note that the team has taken this approach on p. 25 with respect to TOP-002-2.1b, R14. However, Appendix B recommends a threshold at the â€œPoint where [generation] aggregates to >75MVAâ€� for the five â€œHigh Priorityâ€� standards. Appendix B tracks the recommends in the white paper where each standard is discussed, with the exception of VAR-002 â€“ there is no mention of â€œPoint where [generation] aggregates to >75MVAâ€� and neither should there be. We urge the team to reconsider and adopt a consistent â€œpoint where generation aggregates to > 20 MVAâ€� approach in each of these standards (except VAR-002). If a 20 MVA threshold applies to I2 generators and thatâ€™s reliability-based, there would be a reliability gap if a > 75 MVA threshold was adopted.
Wisconsin Electric Power Co	No	The CIP standards must be modified to remove the individual dispersed generator controls from the scope.Given the direction in FERC Order 791 to develop actual auditable requirements for low impact BESCS, the argument that CIP doesnâ€™t need to worry about applicability due to no real requirements is a faulty argument.
Manitoba Hydro	No	The SDT should consider modifications to FAC-001-1. Requirement R1 notes that Facility connection requirements for â€œGeneration Facilitiesâ€� shall be documented. It should be clear in the scope of the standard that any special connection requirements for dispersed power producing resources (Inclusion I4) should be documented. NERC IVGTF 1-3 recommended reactive power requirements be clearly defined as well as any special modeling requirements (eg. aggregation), for example. Frequency response

Organization	Yes or No	Question 1 Comment
		requirements for both under and overfrequency should be documented in FAC-001-1. Also the SDT should consider modifications to VAR-001-3 to include language more appropriate for DGR. Automatic Voltage Regulator in R4 is applicable to conventional synchronous generators and a generic plant-level volt/var controller is more applicable to DGR with a voltage controller controlling the voltage at the point of interconnection. It should be clear that a voltage or Reactive Power schedule can be given by the TO to a DGR. The schedule may be influenced by the technology (eg. switched capacitor banks vs static var compensator). The SDT correctly identifies some standards, such as the MOD standards, where â€œthe SDT will consider the need to develop guidelines for dispersed generation resource modeling and therefore recommends consulting other groupsâ€ that are currently working on these issues. This is inconsistent with the statement in the same section â€œThe existing and proposed modeling standards are sufficient for modeling dispersed generation resourcesâ€. As such it is suggested that the SDT may wish to consult with these groups prior to establishing priorities on some standards.
ISO New England	No	PRC-004-2.1a should not be modified to exclude dispersed power producing resources. From ISO New Englandâ€™s perspective, it is important to know about relay misoperations in order to maintain system reliability. This extends to individual units that make up an aggregated dispersed power producing resource, especially when one considers the potential that similar practices would be used in setting each of the protection systems applied to individual units . FERC has explicitly recognized this in its March 20, 2014 Order Approving Revised Definition, where it stated that: â€œ[f]or example, a wind farm larger than 75 MVA can affect reliability if all of its wind turbines trip offline simultaneously after just a slight fluctuation in voltage or frequency. Therefore, because variable generation can impact the interconnected transmission network, we anticipate that wind plant owners whose facilities meet the inclusion I4 criteria who seek to exclude

Organization	Yes or No	Question 1 Comment
		individual wind turbines from the bulk electric system through the exception process will be infrequent.â€ See North American Reliability Corporation, 146 FERC Â¶ 61,199 (2014) at P 48.
FirstEnergy	Yes	FE questions the need for both PRC-005-1.1b and PRC-005-2. Why not just focus on PRC-005-2
DTE Electric	Yes	No comments
American Electric Power	Yes	AEP supports the efforts of this drafting team, and believes that the approach proposed in the white paper is reasonable (including the importance of focusing on PRC-004, PRC-005, and VAR-002). AEP will review the additional standards that the drafting team believes are and are-not impacted, and will provide comments on those in future comment periods.
EDP Renewables North America LLC	Yes	Section 4.2.2 of the white paper notes that the age of dispersed generation resources affects their ability to provide reliability services. However, identification of relevant standards as described in the Technical Discussion does not refer to age or ability. It is not clear what role those characteristics play in identifying relevant Standards.
PacifiCorp	Yes	
Duke Energy	Yes	
SPP Standards Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power	Yes	

Organization	Yes or No	Question 1 Comment
Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
Xcel Energy	Yes	
Idaho Power Company	Yes	
City of Tallahassee	Yes	
City of Tallahassee, TAL	Yes	
City of Tallahassee - Electric Utility	Yes	
PPL NERC Registered Affiliates		These comments are submitted on behalf of the following PPL NERC Registered Affiliates: Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

2. **The posted white paper and its Appendix B describe how the SDT recommends addressing dispersed power producing resources through changes to the applicability section, guidance documentation, or in the applicability of requirements. Do you agree that the DGR SDT has correctly identified the best approach for each standard? If not, please explain.**

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	The applicability of PRC-004 should not be modified as explained above in the response to Question No. 1.
DTE Electric	No	See Question 3 comments
NEA Joint Commenters (NextEra, Exelon and MidAmercian)	No	The Joint Commenters NEA only agree with the recommended revisions to PRC-004-2.1a, PRC-005 (relevant versions) and VAR-002 at this time, and recommend that the SDT focus on and complete these changes as soon as possible. The Joint Commenters NEA also recommend that the SDT also hand off the suggested guidance issues to NERC Staff to work with the appropriate NERC technical committees to develop and publish any guidance, etc needed for those Standards. The Joint Commenters NEA are concerned that some of the issues raised in the White Paper implicate compliance rather than technical issues, and, thus believe stakeholders are best served with these observations being reviewed by the NERC technical committees. For example, TOP-001, TOP-003 and TOP-006 as discussed in the White Paper do not raise to the level of a change to the requirements, and, thus, guidance can be developed by NERC staff and the Operating Committee with regards to how to apply to dispersed power producing resources, as these standards all relate to communication of real-time status, future outage planning and capabilities of dispersed generating resource. While communication of these data may be feasible from a technical perspective this could be construed as a compliance issue that can be resolved through guidance rather than standard revisions.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf	No	See comments specific to VAR-002 in Q9 and Q10 comments.

Organization	Yes or No	Question 2 Comment
Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
ACES Standards Collaborators	No	agree conceptually with the approach overall but have identified a few standards where we disagree with the assessment. Those are documented in the first and third questions.
Xcel Energy	No	We strongly disagree with the assertion that issues with FAC-008-3 can be addressed with guidance alone. We agree with the SAR recommendations that the applicability of FAC-008 be limited to the point of 75 MVA or above. Furthermore, we think the wording of requirements R1 and R2 is very problematic due to the uncertainty caused by the usage of the term "main step up transformer" as well as the wide variability in the possible location of "the point of interconnection with the Transmission Owner." For example, we have instances where the point of interconnection for one of our wind farms is located at the transmission voltage level (>100 KV) with miles of transmission line/Generator Interconnection Facility between the wind farm aggregating system and the point of interconnection. In this instance, application of FAC-008-3 R1 and R2 is fairly straight forward but could be interpreted to require that we apply ratings criteria to non-BES portions of the aggregating system. We also have wind farms where the point of interconnection to the Transmission Owner system occurs at a main disconnect switch on each of the individual feeders at the aggregating system voltage level of 34.5 KV and at a point prior to aggregation of 75 MVA or greater. The Transmission Owner owns the aggregating system from the main disconnect switch on each feeder through a 34.5 KV bus where the feeders aggregate to >75 MVA and the transformer utilized to step up the output to transmission level voltage. For this facility, application of FAC-008-3 R1 and R2 is entirely dependent on the interpretation of the term "main step-up transformer" and results in R1 and/or R2 requiring analysis of non-BES components or which describe components only owned by the Transmission Owner and not owned by the Dispersed Generation Owner.It is recommended that FAC-008-3 R1 and R2 be simplified to state that: "The Generator Owner must have a ratings methodology and study for the following:For BES generation not included per BES Definition Inclusion I4, from and including the generator to the point of interconnection to the Transmission Owner system. For BES generation included per BES Definition Inclusion I4, for all Generator Owner owned

Organization	Yes or No	Question 2 Comment
		equipment from the point of aggregation of 75 MVA or greater to the point of interconnection to the Transmission Owner system."
Idaho Power Company	No	See comments on proposed changes to PRC-004 below. Otherwise the approaches seem reasonable.
Wisconsin Electric Power Co	No	The VAR-002 target applicability should be at the point of interconnection.
ISO New England	No	The applicability of PRC-004 should not be modified as explained above in the answer to Question No. 1.
EDP Renewables North America LLC	No	The SDT should be as precise as possible in the guidance it provides, since that guidance will be the basis for significant revisions to the numerous Standards identified to date. EDP Renewables North America LLC (EDP Renewables) recommends that the SDT define the terms used to specify â€œTarget Applicabilityâ€ of the Standard revisions. If the terms â€œPoint of common controlâ€, â€œpoint where aggregated to > 75 MVAâ€, and â€œAggregate Facility Levelâ€ are intended to have different meanings, these should be specified. A better approach would be to use the Point of Interconnect as the Target Applicability. This is a well defined industry term. Using the other terms could lead to misunderstanding, and/or result in inconsistency due to individualsâ€™ interpretations.
MRO NERC Standards Review Forum	Yes	Yes this seems reasonable.
SPP Standards Review Group	Yes	The chosen approaches seem reasonable.
Public Service Enterprise Group	Yes	Yes, with respect as to â€œwhatâ€ changes need to be addressed. However, the white paper is unclear as to â€œhowâ€ it will attempt to implement those changes (i.e., the process it will follow). A new column should be added to Appendix B that addresses the how. Here are examples of potential implementation problems that the team should consider:PRC-004-2.1a (Misoperations) is undergoing revisions to PRC-004-3 in Project 2010-05.1 Protection Systems - Phase 1 (Misoperations). How will the team address its needed changes, given that ongoing project? â€¢ The same applies to changes in PRC-005 â€“ a team is developing PRC-005-4 in Project 2007-17.3 Phase 3 of Protection System Maintenance and Testing (Sudden Pressure Relays)â€¢ And same applies to changes in VAR-002 â€“ a team has just completed a passing successive ballot on VAR-002-3 in Project 2013-04 Voltage & Reactive ControlThe question on â€œhowâ€ is administrative, but extremely important. If an existing SDT is working on a standard and a second SDT wants to work on that same standard, but with a different scope, it would be very inefficient to have two teams balloting different versions of the same standard, which must eventually be combined. Only ONE team

Organization	Yes or No	Question 2 Comment
		should be involved in changing a standard at a time. To do that, the existing teamâ€™s SAR (which is its scope) would need to be amended to include the additional scope of the second SDT. I donâ€™t believe the SDT has considered this issue.
Dominion NERC Compliance Policy	Yes	
PacifiCorp	Yes	
FirstEnergy	Yes	
Duke Energy	Yes	
Manitoba Hydro	Yes	
City of Tallahassee	Yes	
City of Tallahassee, TAL	Yes	
City of Tallahassee - Electric Utility	Yes	

3. The posted white paper and its Appendix B identify six standards where guidance may be sufficient to account for the unique characteristics of dispersed power producing resources. Such guidance may include recognition of aggregating common components as a single “Element” for Facility Ratings and using aggregated capacity value, not individualized units, in the modeling needs. Do you agree that the DGR SDT has correctly identified standards for which applicability changes are not needed, but guidance to clarify application of the standard to dispersed power producing resources would be helpful? If not, please explain.

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 3 Comment
Dominion NERC Compliance Policy	No	See preceding comments.
MRO NERC Standards Review Forum	No	The SDT has not made in clear what six (6) Standards they are referring too. Within in Appendix B, there are six (6) standards with the Target Applicability of either â€œPoint where aggregates to > 75 MVAâ€� or â€œIndividual BES Resources / Elementsâ€ � Which six (6) Standards is the SDT referring to?
DTE Electric	No	More clarity would be appreciated regarding the individual vs aggregate approach for the facility ratings Standard. Guidance on the scopeof equipment to be rated for DGRs would be helpful.
ACES Standards Collaborators	No	We agree with all standards except PRC-025. We do not understand why PRC-025 would need to apply to individual generating units in a dispersed generator resource. This would imply that the loss of a single unit at these dispersed generation resource sites would have a reliability impact which would be counterintuitive to this entire standards project. Futhermore, it is not consistent with the drafting teamâ€™s approach that standards that apply to individual generating elements need to be modified. The whitepaper may even contradict the applicability section 3.2.5 of the standard that states â€œElements utilized in the aggregation of dispersed power producing resourcesâ€� which suggests the standard applies to individual generating elements and not the GOP as a whole. We suggest that either PRC-025 should be added to the standards that need the applicability modified or a better explanation for why it does not need to be modified should provided in the whitepaper.
Xcel Energy	No	We strongly disagree with the assertion that issues with FAC-008-3 can be addressed with guidance alone. We agree with the SAR recommendations that the applicability of FAC-008 be limited to the point of 75 MVA or above. Furthermore, we think the wording of requirements R1 and R2 is very

Organization	Yes or No	Question 3 Comment
		problematic due to the uncertainty caused by the usage of the term "main step up transformer" as well as the wide variability in the possible location of "the point of interconnection with the Transmission Owner." For example, we have instances where the point of interconnection for one of our wind farms is located at the transmission voltage level (>100 KV) with miles of transmission line/Generator Interconnection Facility between the wind farm aggregating system and the point of interconnection. In this instance, application of FAC-008-3 R1 and R2 is fairly straight forward but could be interpreted to require that we apply ratings criteria to non-BES portions of the aggregating system. We also have wind farms where the point of interconnection to the Transmission Owner system occurs at a main disconnect switch on each of the individual feeders at the aggregating system voltage level of 34.5 KV and at a point prior to aggregation of 75 MVA or greater. The Transmission Owner owns the aggregating system from the main disconnect switch on each feeder through a 34.5 KV bus where the feeders aggregate to >75 MVA and the transformer utilized to step up the output to transmission level voltage. For this facility, application of FAC-008-3 R1 and R2 is entirely dependent on the interpretation of the term "main step-up transformer" and results in R1 and/or R2 requiring analysis of non-BES components or which describe components only owned by the Transmission Owner and not owned by the Dispersed Generation Owner.It is recommended that FAC-008-3 R1 and R2 be simplified to state that: "The Generator Owner must have a ratings methodology and study for the following:For BES generation not included per BES Definition Inclusion I4, from and including the generator to the point of interconnection to the Transmission Owner system. For BES generation included per BES Definition Inclusion I4, for all Generator Owner owned equipment from the point of aggregation of 75 MVA or greater to the point of interconnection to the Transmission Owner system."
Wisconsin Electric Power Co	No	We think that the target applicability for MOD-032 should be on the aggregate facility level.
EDP Renewables North America LLC	No	EDP Renewables recommends that the SDT specify how common components should be aggregated into â€œElementsâ€ to prevent confusion and inconsistency across Standards and regions. Given the variety of technologies lumped under the dispersed generation rubric, a technically justified, technology neutral approach for the aggregation methodology is needed. The critical mass components must attain to be treated as Elements must be clearly established. EDP Renewables requests confirmation that the statement â€œloss of significant number of unitsâ€ in section 4.2.3. means â€œmore than 75MVA of aggregated capacityâ€.
PacifiCorp	Yes	

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	Yes	With respect to MOD-032, it is important that generators provide accurate models of each individual unit. Therefore, if all units are identical, then providing aggregate information may be sufficient. However, if units are not identical, then generators should be required to provide individual models.
FirstEnergy	Yes	
NEA Joint Commenters (NextEra, Exelon and MidAmercian)	Yes	The Joint Commenters NEA agrees that revisions are not necessary and guidance may be helpful for the following standards FAC-008-3, PRC-019-1, PRC-024-1, PRC-025-1, MOD-025-2 and MOD-032-1. As mentioned above, the Joint Commenters recommend that these Standards and associated observations be provided to NERC Staff for additional work with the relevant NERC technical committee to consider any needed guidance. For FAC-008-3 in particular, the Joint Commenters feel that the guidance document should implicate standard requirements for Dispersed Generation from the point of aggregation greater than 75 MVA, up to the point of interconnect as was indicated in the SAR. For FAC-008, the guidance should address the issue in the SAR, which transformer (point of aggregation) is in scope. Also, why in the FAC-008 analysis in the Whitepaper is there reference to SOLâ€™s? The second paragraph of the FAC-008 analysis seems out of scope.
Duke Energy	Yes	
SPP Standards Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Do the "aggregated facilities" in Appendix B refere to > 75 MVA aggregation points? PRC-024 needs to pertain to common settings for individual generating resources where incorrectly set protection elements could cause > 75 MVA to trip where is it not deisred. The region specific PRC-006 standards should include mention of common mode effects (e.g. for SERC, one must specify the # MW lost when the UF protection activates - this should include the aggregated MW of all units set similarly). This question is a difficult to answer not knowing what the specific guidance will be.
Idaho Power Company	Yes	
Manitoba Hydro	Yes	We agree this would be helpful however, we suggest using the term â€œcommon and electrically similarâ€� dispersed power producing resources rather than â€œcommonâ€�. Dispersed power producing resources with sufficiently different electrical characteristics from a modeling perspective, may be installed at the same location.

Organization	Yes or No	Question 3 Comment
ISO New England	Yes	With respect to MOD-032, it is important that generators provide accurate models of each individual unit. Therefore, if all units are identical, then providing aggregate information may be sufficient. However, if units are not identical, then generators should be required to provide individual models.

4. Section 4.3.3 of the posted white paper describes the prioritization methodology the DGR SDT used to assign high, medium, or low priority to its review of each standard’s applicability in the context of dispersed power producing resources, and Appendix B contains the results of that prioritization. Has the DGR SDT appropriately prioritized the standards? If not, please explain.

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	PRC-004 and associated relay misoperations are important for reliability. Efforts to reduce itâ€™s applicability should not be a priority.
MRO NERC Standards Review Forum	No	The NSRF does not understand why the High priority states: â€œHigh priority was assigned if compliance-related efforts with no appreciable reliability benefit would require not only significant resources but also would require efforts to be initiated by anentity well in advance of the implementation dateâ€�. The NSRF believes that High Priority should have a the STRONGEST reliability benefit, not â€œâ€¦with no appreciable reliability benefitâ€¦â€�. The NSRF does agree with the High, Medium and Low priority prioritization methodology.
NEA Joint Commenters (NextEra, Exelon and MidAmercian)	No	Although the Joint Commenters NEA generally recognize the need to prioritize the SDTs work, it is concerned that the SDT undertook a task that is arguably well outside the scope of the SAR presented to the Standards Committee to include â€œconsideration is necessary for other requirements that affect the interaction of a Balancing Authority (BA), Transmission Operator (TOP), or Reliability Coordinator (RC) with individual BES Elements.â€� As mentioned above, the Joint Commenters NEA recommends that the SDT focus its efforts solely on the implementations of revisions to PRC-004-2.1a, PRC-005 (relevant versions) and VAR-002.
Xcel Energy	No	We believe clarification of FAC-008-3 requires higher priority. See our comments concerning FAC-008-3 in Questions 2 and 3 above. The remaining concern we have is regarding timing of standard changes. We understand that the SDT has internal

Organization	Yes or No	Question 4 Comment
		completion milestones of balloted standards to be sent to BOT approval November 2014, and February 2015, and this leaves more than a year for final NERC BOT and FERC approval. We understand that based on past completion history, this allows a reasonable timeframe of more than a year to expect these final steps to occur. The effort and focus of this SDT seems outstanding, however, we remain skeptical that so many standards can be changed properly to prevent a 'nonsense' non-compliant condition on the BES Definition effective date of July 1, 2014. We strongly recommend that this SDT, and appropriate members of the BOT and FERC, develop a contingency milestone at an appropriate point in the process, say February 2015, to determine if there are any needed standard revisions in delay, that could create an unnecessary noncompliance condition on the effective date. This effort is expected to be needed to expedite any standards that have been clearly identified as needing dispersed generation applicability exemptions, but are lagging in the process and could create an unneeded issue on the effective date.
Manitoba Hydro	No	In addition, changes to FAC-001-1 should be added to the high priority and changes to VAR-001-3 added to the low priority list. The justification for establishing â€œHighâ€� vs â€œMediumâ€� priority levels for standards is not clear. It is possible that the choice of wording does not clearly explain the difference between the two levels. It is suggested that these two priority level justifications be reworded for clarity.
ISO New England	No	PRC-004 and associated relay misoperations are important for reliability. Efforts to reduce itâ€™s applicability should not be a priority.
Dominion NERC Compliance Policy	Yes	Dominion agrees with the prioritization methodology as well as the priority assigned to each stanadard. However, Dominion does not agree with the Target Applicability assigned to some of the TOP standards (see previous comment) and suggests the SDT be consistent in verbiage used or explain if there is a reason for the differences. Examples are: Point where aggregates to >75MVA and Aggregate Facility Level.

Organization	Yes or No	Question 4 Comment
PacifiCorp	Yes	
FirstEnergy	Yes	Approach seems logical for prioritization of Standards to be revised.
Duke Energy	Yes	
SPP Standards Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
ACES Standards Collaborators	Yes	We agree conceptually with the approach.
Public Service Enterprise Group	Yes	
Idaho Power Company	Yes	
Wisconsin Electric Power Co	Yes	
EDP Renewables North America LLC	Yes	

Organization	Yes or No	Question 4 Comment
PPL NERC Registered Affiliates		
DTE Electric		No comments

5. **In section 5.10.4 the DGR SDT recommends changing the applicability of PRC-004-2.1a. Has the DGR SDT provided adequate justification or rationale to support revising the applicability of PRC-004-2.1a? If not, please either provide additional reliability-based justification or explain what is needed**

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	The justification provided by the SDT is contrary to FERCâ€™s March 20, 2014 Order (please refer to the response to Question No. 1 above).
Public Service Enterprise Group	No	As stated and supported in response to question 1, we believe the aggregate threshold should be > 20 MVA, not > 75 MVA. If a 20 MVA threshold applies to I2 generators and thatâ€™s reliability-based, there would be a reliability gap if a > 75 MVA threshold was adopted.
Manitoba Hydro	No	Section 5.10.4 relates applicability of PRC-004 to PRC-024 but is not clear what is proposed to be changed in PRC-004. The current applicability used in PRC-024 is for all generating units with some technical modifications for asynchronous units. We agree that the applicability should not apply to individual units within a DGR.
ISO New England	No	The justification provided by the SDT is contrary to FERCâ€™s March 20, 2014 Order (please see our answer to Question No. 1 above).
EDP Renewables North America LLC	No	Instead of opening a debate about the relationship between misoperations and common mode trips, PRC-004â€™s applicability should be limited to individual protection system components that affect > 75 MVA of capability.
Dominion NERC Compliance Policy	Yes	Dominion agrees with the SDT that the Misoperations of any individual generating unit may not have an impact upon the BPS and agrees that it is not necessary to analyze Protective System Misoperations affecting individual generation units of dispersed generation resources. Dominion further supports the analysis of potential Misoperations of dispersed generation resources if the trip is greater than 75 MVA of aggregate occurs in response to a system disturbance. Dominion supports the continued review and study of the potential reporting process for Misoperations required by dispersed generation resources due to the limited information available due to turbine design and technology that would be available for analysis and reporting.
PacifiCorp	Yes	

Organization	Yes or No	Question 5 Comment
MRO NERC Standards Review Forum	Yes	The NSRF agrees and would like to have the wording in the applicability statement that PRC-004-2.1a will only be implemented when there is a trip greater the or equal to 75 MVA, or words to that effect.
FirstEnergy	Yes	How will this Project be coordinated with the current efforts on Project 2010-05.1, Phase I of Protection System Misoperations.
DTE Electric	Yes	
NEA Joint Commenters (NextEra, Exelon and MidAmercian)	Yes	The Joint Commenters NEA believe that the technical basis for the Standard change for I4 BES dispersed generation (i.e., wind and solar) is clear and supported. As such, the Joint Commenters NEA also concur with the SDTâ€™s decision to defer to the BES Reference Documentâ€™s description of I4 â€œdispersed power producing resourcesâ€� in the analysis as noted on page 5 of the Draft White Paper, as this description clearly is intended to identify the unique and â€œnon-traditionalâ€� variable generation such as wind and solar, rather than traditional resources such as fossil generating resources.
Duke Energy	Yes	
SPP Standards Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Xcel Energy	Yes	We agree with SDT that the analysis and the Mitigation of Generator Protection System Misoperations should not extend to each individual generating unit.
Idaho Power Company	Yes	
Wisconsin Electric Power Co	Yes	
City of Tallahassee	Yes	
City of Tallahassee, TAL	Yes	
City of Tallahassee - Electric Utility	Yes	
ACES Standards Collaborators		We believe adequate justification has been provided.

6. The DGR SDT believes it is not necessary under PRC-004 to analyze protection system misoperations affecting individual dispersed generating units, but is concerned with the potential for unreported misoperations involving a common mode trip of several generating units. The DGR SDT proposes requiring analysis for potential misoperation of individual generating units, if a trip of greater than 75 MVA aggregate occurs in response to a system disturbance. Do you agree with this approach? If not, please provide specific examples or rationale to support an alternate approach.

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	No	We do not agree with this approach because limiting the analysis requirement to a trip of greater than 75 MVA only accounts for very large occurrences that could be unusual. Smaller occurrences, however, may predict an unusual large occurrence that could impact reliability especially when one considers the potential that similar practices would be used in setting each of the protection systems applied to individual units.
Public Service Enterprise Group	No	As stated and supported in response to question 1, we believe the aggregate threshold should be > 20 MVA, not > 75 MVA. If a 20 MVA threshold applies to I2 generators and thatâ€™s reliability-based, there would be a reliability gap if a > 75 MVA threshold was adopted.
Idaho Power Company	No	Based on the discussion for TOP-001-1a R7 and TOP-002-2.1b R14, the SDT might consider the analysis of a trip of greater than 20 MVA. The rationale seem similar that if the loss of 20 MVA of generation is necessary to plan for, then it would be significant enough to analyze when it lost.
Manitoba Hydro	No	One of the areas of concern with DGR is the ability to ride through disturbances (e.g. low voltage ride through). We disagree that a trip greater than 75 MVA should only be considered as this would remove a lot of DGR from consideration. The timing of a disturbance may correlate with a period when the output of the DGR is low. In this case, the reliability impact of the lost generation may be low but the misoperation may point to a problem that could occur at any output level. Perhaps, to set a reasonable boundary, protection misoperation that occurs when DGR had an output of 20 MVA or greater should be analyzed in PRC-004.
ISO New England	No	We do not agree with this approach because limiting the analysis requirement to a trip of greater than 75 MVA only accounts for very large occurrences that could be unusual. Smaller occurrences, however, may predict an unusual large occurrence that could impact reliability especially when one considers the potential that similar practices would be used in setting each of the protection systems applied to individual units.

Organization	Yes or No	Question 6 Comment
EDP Renewables North America LLC	No	PRC-004â€™s applicability should be limited to any individual protection system component that affects > 75 MVA of capability. Additionally, the reliability of the Bulk Electric System would not be compromised should the individual generator trips occur over a period greater than sixty cycles. Within the White Paper, the SDT denotes that, â€œProtection system maintenance on individual generating units at a dispersed generation facility would not provide any additional reliability benefits to the BESâ€¦â€ The applicability of PRC-001, PRC-004, and PRC-005 should be congruent.
Alliant Energy	No	We understand the SDTâ€™s concern with regard to a common mode trip of several generating units. However, we do not support any language that would effectively bring turbine control systems in scope for PRC-004, in lieu of protection systems which is the current scope of PRC-004.
MRO NERC Standards Review Forum	Yes	The NSRF agrees and would like to have the wording in the applicability statement that PRC-004-2.1a will only be implemented when there is a trip greater the or equal to 75 MVA, or words to that effect.
FirstEnergy	Yes	It is consistent with the requirement for existing BES identified generating units.
DTE Electric	Yes	The applicability statement should be clear in that individual generating unit trips should only be analyzed relative to comon mode trips.
NEA Joint Commenters (NextEra, Exelon and MidAmercian)	Yes	The Joint Commenters NEA believe that the technical basis for the Standard change for I4 BES dispersed generation (i.e., wind and solar) is clear and supported. As such, the Joint Commenters NEA also concur with the SDTâ€™s decision to defer to the BES Reference Documentâ€™s description of I4 â€œdispersed power producing resourcesâ€ in the analysis as noted on page 5 of the Draft White Paper, as this description clearly is intended to identify the unique and â€œnon-traditionalâ€ variable generation such as wind and solar, rather than traditional resources such as fossil generating resources.
ACES Standards Collaborators	Yes	The SDTâ€™s approach is supported by the fact that the threshold for dispersed generation resources is 75 MVA for inclusion in the BES. If the facility impacts the BPS reliability, it will be included in the BES. Thus, a loss of less than 75 MVA of dispersed generation resources by definition cannot impact BPS reliability and, thus, analysis of misoperations of Protection Systems is unnecessary when less than 75 MVA of generation will be lost.
Dominion NERC Compliance Policy	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
SPP Standards Review Group	Yes	

Organization	Yes or No	Question 6 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Xcel Energy	Yes	
Wisconsin Electric Power Co	Yes	
City of Tallahassee	Yes	
City of Tallahassee, TAL	Yes	
City of Tallahassee - Electric Utility	Yes	

7. **In section 5.10.6 the DGR SDT recommends making several changes to tailor the applicability of PRC-005 for dispersed power-producing resources. Has the DGR SDT provided adequate justification or rationale to support revising the applicability of PRC-005? If not, please either provide additional reliability-based justification or explain what is needed.**

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	In general, relay maintenance is a vital part of system reliability and reducing the applicability of the standard seems counter to good utility practice.
Public Service Enterprise Group	No	As stated and supported in response to question 1, we believe the aggregate threshold should be > 20 MVA, not > 75 MVA. If a 20 MVA threshold applies to I2 generators and thatâ€™s reliability-based, there would be a reliability gap if a > 75 MVA threshold was adopted.
ISO New England	No	In general, relay maintenance is a vital part of system reliability and reducing the applicability of the standard seems counter to good utility practice.
City of Tallahassee	No	Tal agrees with the exclusion of aggregate levels of generation below 75MVA. Tal would prefer to see justification of the 75 MVA brightline for the requirement of protection devices to be included under PRC-005.
City of Tallahassee, TAL	No	TAL agrees with the the exclusion of aggregate levels of generation below 75MVA. TAL would prefer to see a justification of the 75MVA brightline for the requirement of protection devices to be included under PRC-005.
City of Tallahassee - Electric Utility	No	TAL agrees with the the exclusion of aggregate levels of generation below 75MVA. TAL would prefer to see a justification of the 75MVA brightline for the requirement of protection devices to be included under PRC-005.
Dominion NERC Compliance Policy	Yes	
PacifiCorp	Yes	
MRO NERC Standards Review Forum	Yes	

Organization	Yes or No	Question 7 Comment
FirstEnergy	Yes	Required reporting of aggregated facility equipment consistent with BES definition is the proper methodology.
DTE Electric	Yes	
NEA Joint Commenters (NextEra, Exelon and MidAmercian)	Yes	The Joint Commenters NEA believe that the technical basis for the Standard change for I4 BES dispersed generation (i.e., wind and solar) is clear and supported. As such, the Joint Commenters NEA also concur with the SDTâ€™s decision to defer to the BES Reference Documentâ€™s description of I4 â€œdispersed power producing resourcesâ€ in the analysis as noted on page 5 of the Draft White Paper, as this description clearly is intended to identify the unique and â€œnon-traditionalâ€ variable generation such as wind and solar, rather than traditional resources such as fossil generating resources. The drafting team should take care to address only issues related to the unique nature of these non-traditional resources and not duplicate issues already addressed in the PRC-005 standard and itâ€™s supporting documents such as protection systems at the interfaces.
SPP Standards Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	The current revision project to PRC-005 is 2007-17.3 (it is shown incorrectly in the last paragraph of section 5.10.6)
ACES Standards Collaborators	Yes	We believe adequate justification for the revisions have been provided.
Xcel Energy	Yes	
Idaho Power Company	Yes	
Wisconsin Electric Power Co	Yes	The second paragraph in this section in part states â€œShould these protection elements fail to remove the generating unit for this scenario, the impacts would be limited to the loss the individual generating unit and potentially the next device upstream in the collection system of the dispersed generation resourceâ€. If the next device upstream is the collection system and it is greater than 75 MVA then this argument needs additional clarification. If the applicability of dispersed power-producing resources is not changed, we would ask the SDT to provide guidance for the testing of these elements considering the safety, physical constraints and elements that are part of protection systems that were not considered in PRC-005 as it is written. For example, parts of the protection

Organization	Yes or No	Question 7 Comment
		systems of wind turbines cannot be accessed when they are running because of safety reasons. In addition, the system protection elements of some dispersed power-producing resources include molded case circuit breakers, power circuit breakers with trip units, UPSs and other devices that are not currently in PRC-005.
Manitoba Hydro	Yes	
EDP Renewables North America LLC	Yes	The applicability of PRC-001, PRC-004, and PRC-005 should be congruent.

8. With respect to the PRC standards, do you believe a common mode failure which results in misoperation of a large number of the individual generating resources at a dispersed generation resource site may impact BES reliability? Please explain your answer.

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 8 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Only in rare cases of multiple contingencies might a misoperation of a large number of the individual generating resources at a dispersed generation resource site impact BES reliability.
ACES Standards Collaborators	No	For the vast majority of dispersed generating resources, we do not believe that a common mode failure for that dispersed generating resource site would be impactful to reliability in most cases. First, most of these sites are not that large. Second, because the output is variable, these resources must be backed up with operating reserve to account for their variability. Third, there are other NERC standards that require operation of the BES to withstand the next contingency so the loss of entire wind farm or solar array will not be impactful to reliability unless another standard is concurrently violated.

Organization	Yes or No	Question 8 Comment
Xcel Energy	No	The aggregate size of the common mode failure must be considered to determine the impact to grid reliability. We suggest the existing threshold value of 75 MVA. In addition, we believe that this would have to do more with a setting associated with PRC-019, PRC-034, and PRC-025. These common mode failures would not be a classical PRC-004 operation analysis because the equipment is not in-scope.
EDP Renewables North America LLC	No	For consistency and to prevent confusion, a specific capability limit (>75 MVA) should be used. It is widely agreed that until capability aggregates to that level, BES reliability is not threatened.
Dominion NERC Compliance Policy	Yes	Dominion believes that a misoperation that results in the loss of dispersed power generation for resources greater than 74MV may have a significant impact on BES reliability. We thefore support a threshold of 75 MVA for such resources under this standard.
PacifiCorp	Yes	The SDT recognizes concern with the potential for reliability impacts involving a common mode failure that leads to (1) loss of a significant number of generating units or the entire facility (White Paper Section 4.2.3 â€“ Page 8) or (2) the potential for misoperations involving several individual generating units (5.10.4 â€“ Page 19). PacifCorp shares this concern. The reliability impacts of a common mode failure and related loss of units at a dispersed generation resource site may affect reliability depending upon the magnitude, timing, and duration of the resource loss. PacifiCorp agrees with the SDT proposal of requiring analysis for potential Misoperation of individual generating units, if a trip of greater than 75 MVA aggregate occurs in response to a system disturbance.
Northeast Power Coordinating Council	Yes	Yes, as explicitly recognized by FERC, a wind farm larger than 75 MVA can affect reliability if all of its wind turbines trip offline simultaneously after just a slight fluctuation in voltage or frequency.In addition, loss of a wind farm as a dispersed generation resource has been observed real time to impact Quebecâ€™s Main

Organization	Yes or No	Question 8 Comment
		Transmission System (the Quebec equivalent of the BES). In Quebec, all the generation or dispersed generation greater than 50MVA connected into 44kV and above are included in its Main Transmission System.Because of the variability of system loads (peak, off-peak, shoulder periods), and the electrical locations of generating resources and their impacts on the BES, what is a large number of generating resources?
MRO NERC Standards Review Forum	Yes	Yes, and recommend that the 75 MVA threshold be used as in PRC-004.
FirstEnergy	Yes	The BES definition has provided technical justification for a threshold of 75 MVA of aggregated generation viewed as having reliability impact on the BES. The PRC Standards focus on loss of this and higher levels of generating resources.
DTE Electric	Yes	BES reliability could be impacted if a concurrent loss of individual generating units aggregating to nore than seventy five MVA occurs.
NEA Joint Commenters (NextEra, Exelon and MidAmercian)	Yes	For the purposes of limiting misoperations reporting to an entire site as opposed to individual resources.
Duke Energy	Yes	Duke Energy agrees with the SDTs recommendation that if a trip of generation resulting in the aggregate loss of 75MVA or greater occurs, then an analysis of potential Misoperations of the individual generating units should take place.
SPP Standards Review Group	Yes	With significant numbers of dispersed generation resources currently in existence and more being placed into service daily, the issue of a, misoperation (common mode) of a large number of individual generating resources becomes more probable. Not that such an event would be any more detrimental to the reliability of the BES than the loss of a comparable amount of traditional generation, the impact would be about the same.

Organization	Yes or No	Question 8 Comment
Public Service Enterprise Group	Yes	A common mode failure could be caused by either a consistently applied bad relay setting (more likely) or consistently bad relays (less likely).
Idaho Power Company	Yes	since 75MVA has been determined to be cut off for significance to the reliably operation of the BPS, I would think a loss of any 75MVA generating resource would be considered equally (not considering MVAR capability!)
Wisconsin Electric Power Co	Yes	Agreed as long as the â€œlarge numberâ€� is greater than 75 MVA.
Manitoba Hydro	Yes	Common mode failures, such as the ability to ride through low voltages or low frequency, can impact reliability. It is possible to have groups of DGR in close electrical proximity that may also experience the same common mode failure, making the system more prone to underfrequency or other reliability event. Ground fault relays that are not coordinated can also result in loss of DGR for BES faults. The impact would depend on the definition of â€œlargeâ€�, the location of the dispersed generation resource, whether tapped off of a major BES high voltage transmission tie or not, and the type of common mode failure. For example if it is tapped off a BES transmission tie line, special considerations , such as installing a three ring breaker at the POI or adding/modifying an SPS may be necessary to minimize the impact to BES reliability.
ISO New England	Yes	Yes, as explicitly recognized by FERC, a wind farm larger than 75 MVA can affect reliability if all of its wind turbines trip offline simultaneously after just a slight fluctuation in voltage or frequency.
City of Tallahassee	Yes	
City of Tallahassee, TAL	Yes	

Organization	Yes or No	Question 8 Comment
City of Tallahassee - Electric Utility	Yes	

9. **In section 5.13.2 of the white paper, has the DGR SDT provided adequate justification or rationale to support revising the applicability of VAR-002-2b? If not, please either provide additional reliability-based justification or explain what is needed**

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 9 Comment
Dominion NERC Compliance Policy	No	We do not support a blanket exclusion of dispersed power producing resources from requirements 4 & 5. If such respurces have been traditionally excluded then we would expect their respective TO and TP to continue such exclusion, if they so choose.
Northeast Power Coordinating Council	No	In general, providing voltage regulation at the point of aggregation is acceptable. However embedded dynamic devices may affect aggregate voltage performance. The â€œclarificationâ€ needs to address this.
MRO NERC Standards Review Forum	No	Section 5.13.2 uses the words of â€œaggregate facility levelâ€. The NSRF recommends that Facility use a capitol F. This term is used like the Target Applicability which is not defined. Within Appendix B under column â€œTarget Applicabilityâ€ there are four (4) different applications; â€œPoint where aggregates to > 75 MVA, Individual BES Resources / Elements, Point of common control, and Aggregate Facility Level. Without these attributes being defined, the industry cannot know if the Standards within Appendix B have the proper â€œTarget Applicabilityâ€.
Wisconsin Electric Power Co	No	Technical justification should recognize that an individual dispersed generating resource does not provide sufficient reactive resources to provide reliability of the BES.
ISO New England	No	In general, providing voltage regulation at the point of aggregation is acceptable. However imbedded dynamic devices may affect aggregate voltage performance. The â€œclarificationâ€ needs to address this.
EDP Renewables North America LLC	No	Dispersed generation resources are often required to install reactive devices as a condition of interconnection. The applicability of VAR-002 should specify how these devices should be treated when establishing voltage schedules and performance expectations. This may be a Standard that should take into account the capability (â€œolder dispersed generation resourcesâ€) of a resource. Further, if dispersed

Organization	Yes or No	Question 9 Comment
		generation is to include storage devices, care should be taken that requirements are technology neutral. Rather than using the Agregate Facility Level, the reference point for maintaining the voltage schedule, usually the Point Of Interconnect, shall be used.
PacifiCorp	Yes	
FirstEnergy	Yes	
NEA Joint Commenters (NextEra, Exelon and MidAmercian)	Yes	The Joint Commenters NEA believe that the technical basis for the Standard change for I4 BES dispersed generation (i.e., wind and solar) is clear and supported. As such, the Joint Commenters NEA also concur with the SDTâ€™s decision to defer to the BES Reference Documentâ€™s description of I4 â€œdispersed power producing resourcesâ€� in the analysis as noted on page 5 of the Draft White Paper, as this description clearly is intended to identify the unique and â€œnon-traditionalâ€� variable generation such as wind and solar, rather than traditional resources such as fossil generating resources.
Duke Energy	Yes	
SPP Standards Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	VAR-002-2b should apply only to dispersed generation resources that are designed to provide voltage and/or reactive support for the BES. This includes those where voltage or reactive sources (cap banks, reactor banks, static var devices, plant voltage outer-loop control, etc.) which are installed specifically to provide system voltage and reactive support at the point of interconnection or aggregate facility level. Dispersed generation resources that do not have such capability by design should be exempted from VAR-002-2b.
ACES Standards Collaborators	Yes	We believe adequate justification has been provided.
Xcel Energy	Yes	
Idaho Power Company	Yes	
Manitoba Hydro	Yes	The individual generator transformers within the DGR can be excluded in R4 and R5 in favor of the main aggregating transformer connected to the BES. Revised applicability should also be included in R3. There can be power factor correction capacitors located within each individual generator transformer. Only major sources of Reactive Power that impact the BES should be included in the applicability of R3. Terminology of â€œautomatic voltage regulator (AVR)â€� could be adjusted to in

Organization	Yes or No	Question 9 Comment
		VAR-002-2b to reflect the technology used in a DGR â€“ see comments to Question 1.
DTE Electric		No comments

10. With respect to VAR-002-2b, does the NERC DGR SDT need to provide guidance to ensure dispersed power producing resources individual generator transformers are subject to the R4 and R5, as they are not used to improve voltage performance at the point of interconnection?

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 10 Comment
Dominion NERC Compliance Policy	No	
Northeast Power Coordinating Council	No	There is no need to modify the applicability of R4 and R5 of VAR-002-2b. The information under R4 has to be provided only upon request of the Transmission Planner and Transmission Operator. If this information is not necessary, it should not be requested and, accordingly, there is no need to modify the standard. Similarly, R5 is only applicable if the Transmission Operator requests a change to the tap setting. The Transmission Operator should only do this when necessary; therefore, there is no need to modify the applicability of the standard. In addition, other reactive devices, such as embedded dynamic reactive devices,may affect aggregate voltage performance and should be addressed.
FirstEnergy	No	If the individual generator transformers are below the BES defined level then R4 and R5 should not apply.
Duke Energy	No	We believe the SDT may have misstated question 10. We do not believe that individual generator transformers should be subject to R4 and R5. The White paper leads the reader to believe that this question should be asking if we agree that individual generators should â€œnotâ€� be subject to R4 and R5. Please clarify the SDTs intent for this question.
Xcel Energy	No	As worded, this question does not agree with the white paper. Xcel Energy supports the position put forth in the white paper, which states that R4 and R5 of the VAR-002-2b standard would not be applicable to the individual units.
Idaho Power Company	No	
Wisconsin Electric Power Co	No	We would agree if the question included â€¦transformers are NOT subject to the R4 and R5â€¦In addition, has the DGR SDT considered coordination with Project 2013-04, Voltage and Reactive Control, VAR-002-3 on any proposed changes regarding clarifying applicability?
Manitoba Hydro	No	If the applicability is revised as per Question 9, additional guidance should not be needed.

Organization	Yes or No	Question 10 Comment
ISO New England	No	There is no need to modify the applicability of R4 and R5 of VAR-002-2b. The information under R4 has to be provided only upon request of the Transmission Planner and Transmission Operator. If this information is not necessary, it should not be requested and, accordingly, there is no need to modify the standard. Similarly, R5 is only applicable if the Transmission Operator requests a change to the tap setting. The Transmission Operator should only do this when necessary; therefore, there is no need to modify the applicability of the standard. In addition, other reactive devices, such as embedded dynamic reactive devices,may affect aggregate voltage performance and should be addressed.
PacifiCorp	Yes	PacifiCorp agrees that dispersed power producing resource individual generator transformers have traditionally been excluded from VAR-002-2b R4 and R5, as they are not used to improve voltage performance at the point of interconnection, and further agrees with the SDT on the need to clarify the applicability of VAR-002-2b to exclude dispersed power producing resource individual generator transformers from R4 and R5 up to the point of aggregation of 75 MVA, as they are not used to improve voltage performance at the point of interconnection.
MRO NERC Standards Review Forum	Yes	The SDT needs to provide less guidance whereby the GO/GOP can develop their own way of meeting the TOPâ€™s voltage schedule. The SDT should not be so granular to discuss items that are on the collector system, which is not a BES asset.
NEA Joint Commenters (NextEra, Exelon and MidAmercian)	Yes	The Joint Commenters NEA believe that the technical basis for the Standard change for I4 BES dispersed generation (i.e., wind and solar) is clear and supported. As such, the Joint Commenters NEA also concur with the SDTâ€™s decision to defer to the BES Reference Documentâ€™s description of I4 â€œdispersed power producing resourcesâ€� in the analysis as noted on page 5 of the Draft White Paper, as this description clearly is intended to identify the unique and â€œnon-traditionalâ€� variable generation such as wind and solar, rather than traditional resources such as fossil generating resources. In particular there are no reliability benefits to be gained by requiring R4 and R5 to be applicable to the individual generator transformers at a dispersed generation facility; as such, these requirements should be implemented on the aggregating equipment only.
SPP Standards Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern	Yes	It should be clear that the plant step-up transformer (HV side > 100kV) should be included in the R4 and R5, but that any individual resource transformer (HV side < 100kV) is not included in the scope.

Organization	Yes or No	Question 10 Comment
Company Generation; Southern Company Generation and Energy Marketing		
ACES Standards Collaborators	Yes	We believe that guidance or modification to the standard is necessary to ensure that VAR-002-2b only applies to a step-up transformer at the interconnection point to the BES for the dispersed generating resource.
EDP Renewables North America LLC	Yes	It is necessary to exclude these transformers form requirements R4 and R5.
DTE Electric		No comments

11. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 11 Comment
Dominion NERC Compliance Policy	No	
Northeast Power Coordinating Council	No	
FirstEnergy	No	
DTE Electric	No	
Duke Energy	No	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
Xcel Energy	No	

Organization	Yes or No	Question 11 Comment
Idaho Power Company	No	
ISO New England	No	
City of Tallahassee	No	
City of Tallahassee, TAL	No	
City of Tallahassee - Electric Utility	No	
Alliant Energy	No	
PacifiCorp	Yes	As discussed in White Paper Sections 5.10.11 and 5.10.12 (applicable to PRC-024 and PRC-025), PacifiCorp supports the point made by the SDT, that for the purpose of compliance evidence it may be sufficient to provide the settings of a single sample unit within a site as these units are typically set identically, rather than providing documentation for each individual unit.
MRO NERC Standards Review Forum	Yes	Section 4.2.2, First paragraph, Please note that just because technology exist in short term forecasting capabilities, there are small entities that may not have these expensive tools. There may have been State Laws that mandated the use of dispersed power producing resources within their capacity portfolios. Recommend section 4.2.2, be updated to read that technology exist but may not be employeed by entityâ€™s with dispersed power producing resources.Section 4.2.2, Second paragraph, as stated above, the same is true for concerning voltage and frequency system support. The majority of dispersed power producing resources provide real power and voltage which is provided by a fixed power factor control. The SDTâ€™s White Paper needs to take in many system configurations, we are not all created

Organization	Yes or No	Question 11 Comment
		equal.Please note that the NSRF cannot comment on the Priority of Standards listed in appendix B since the Target Applicability terms are not defined.
PPL NERC Registered Affiliates	Yes	The SDT states on p.7 of the Whitepaper that â€œDispersed generation resources are often considered to be variable energy resources such as wind and power, â€œ but, â€œThis description is not explicitly stated in the BES definition.â€ The SDTâ€™s comment that â€œNERC and FERC characterize variable generation in this manner,â€ is helpful, but the absence of a formal definition of Dispersed Generation Resources remains a concern. We request that the term Dispersed Generation Resources be formally defined in the NERC Glossary.
NEA Joint Commenters (NextEra, Exelon and MidAmercian)	Yes	Section 4.2. Dispersed generation resources are often variable energy resources such as wind and solar.Section 4.2.1. The generating capacity of individual dispersed generating modules can be as small as a few hundred watts to as large as several megawatts. The utilization of these small generating unitsâ€™ results in a large number of units (e.g., several hundred wind generators or several million solar panels) installed collectively as a single facility that is connected to the transmission system.
SPP Standards Review Group	Yes	We note that the SDT swings back and forth between the BPS and BES. Shouldnâ€™t we restrict ourselves to the BES since the reliability standards are about preserving the reliability of the BES?We donâ€™t quite understand the statement that begins the Section 4.2.1 Design Characteristics. It states â€˜For dispersed power producing resources to be economically viable, it is necessary for the equipment to be geographically dispersed.â€™ Could the SDT expand on this?Use a lower case â€˜tâ€™ in â€˜theâ€™ in the italicized sentence at the end of Section 5.4.4 FAC-008 â€“ Facility Ratings. A similar error appears in Section 5.7.7.The opening statement in Section 5.6.2 IR0-005 â€“ Reliability Coordination â€“ Current Day Operations mentions only one of the requirements in the standard that applies to Generator Operators which does not provide a total picture of the purpose of the standard. The statement refers to Requirement R10. However, Requirement R6 also applies to

Organization	Yes or No	Question 11 Comment
		Generator Operators regarding the development of action plans to address potential or actual SOL, DCS or CPS violations. Although the conclusion reached in Section 5.6.2 wonâ€™t change with this additional information, it does provide a fuller picture of what the Generator Operatorâ€™s responsibilities are with regards to the standard.Something appears to be missing at the end of the 3rd line of the 3rd (R3) paragraph under Section 5.10.1. My quess is that the SDT meant to say â€˜â€¦non-operation of an interconnected entityâ€™s Protection Systems,â€¦â€™ However, â€˜protectionâ€™ is not capitalized in the text, so Iâ€™m unsure just what belongs here.Replace the â€˜isâ€™ in the 1st sentence of the paragraph under Section 5.10.2 with â€˜has beenâ€™ such that the sentence reads â€˜â€¦, which has been adopted by the NERCâ€¦â€™.There are numerous references to Real-time in the White Paper. Be sure to use the NERC Glossary spelling in those references.Delete the extra â€˜inâ€™ in the 6th line in Section 5.11.3.1.The phrase â€˜to the natureâ€™ in the 1st bullet of Section 5.11.3.2 doesnâ€™t seem to fit nor add anything to the sentence. Iâ€™d suggest deleting it. Delete the â€˜theâ€™ in the last line of that same paragraph and replace it with â€˜its hostâ€™.Delete the plural â€˜sâ€™ in â€˜resourcesâ€™ in the 1st line of the last paragraph of Section 5.11.3.3.Replace â€˜the SDT projectâ€™ in the 8th line of the 2nd paragraph under Section 5.11.4.2 with â€˜Project 2014-01â€™. In that same paragraph, delete the â€˜inâ€™ in the next to last line in the italicized sentence at the end of the paragraph. These same errors appear in Section 5.11.5.The conclusion in the italicized sentence at the end of Section 5.14.1 is not supported by the sentence immediately preceding it.
ACES Standards Collaborators	Yes	(1) Although there was discussion of the NPCC and SERC versions of PRC-006-1, we did not see any discussion regarding the NERC version of PRC-006. This needs to be included.(2) We are concerned about the coordination of some changes with other drafting teams identified for several requirements in the whitepaper. Some drafting teams have already reached a point where it is too late for coordination. For example, PRC-001 is to be coordinated with the Project 2014-03 TOP IRO drafting team. However, that drafting team is currently preparing documentation to post for public comment in May and will have completed preparations by the time this

Organization	Yes or No	Question 11 Comment
		comment is received. Better coordination with other drafting teams appears to be warranted.
Wisconsin Electric Power Co	Yes	Executive summary of white paper: "â€¦ the intent of this effort is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed generation resources, where the status quo does not create a reliability gap.â€ We disagree with the language about â€œbeing applied over timeâ€ because each Regional Entity could have been applying it differently. Section 5.10.1 PRC-001-1.1: We agree that the SDT should push this issue on the current Project SDTâ€™s, but what happens in the interim? Will the Project teams for 2007-06 and 2014-03 finish in time so that our compliance is not affected? Section 5.10.11 PRC-024: Note that the SDT â€œ â€¦ has determined it is necessary to require that Protection Systems applied on both the individual generating units, as well as any aggregating facilities, are set within the â€œno-trip zoneâ€ referenced in the requirements to maintain reliability of the BPS.â€ SDT says no changes to applicability are required, but states an RSAW or guidance should specify compliance evidence requirements. We did not think an RSAW could specify compliance requirements; only standards could specify compliance requirements.
Manitoba Hydro	Yes	It is suggested that the data provided in the table in Section 5 (page 11) be rearranged for clearer presentation of the information. Subtotals for â€œNERC Standardsâ€ and â€œRegion-specific Standards (*Out of Scope)â€ may be placed at the end of their respective categories rather than at the beginning.
EDP Renewables North America LLC	Yes	It would be beneficial if the applicabilities were defined within the NERC Glossary. It would be prudent to include the same applicability recommendation to each of the Project teams (i.e. Project 2014-03 and Project 2014-01), to ensure that both PRC-001 and PRC-005 view the same applicability as it applies to dispersed generation resources.

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

This version of PRC-005 contains revisions to thea pplicability of the Standard intended to clarify application of its Requirements to Bulk Electric System dispersed power producing resources. PRC-005-3, a subsequent version of PRC-005, has been adopted by the NERC Board of Trustees and is pending regulatory approval. Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-005-2(X) for balloting purposes, may be filed for regulatory approval. The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is concurrently making technical revisions to PRC-005 in Project 2007-17.3 to address FERC directives. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-005 to dispersed power-producing resources.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Maintenance**
2. **Number:** PRC-005- X
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems 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 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 Special Protection System (SPS) for BES reliability.

> The only revisions made to this version of PRC-005 are revisions to section 4.2, 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.
>
> This version is labeled PRC-005-2(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-005 are in development to reflect the fact that applicability changes need apply for versions of the standard that are approved (PRC-005-2), pending regulatory approval (PRC-005-3), and in development in Project 2007-17.3. Depending on the timing of approvals of other versions, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:

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 for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems 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.

> **Rationale for 4.2.5:** In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

4.2.6 Protection Systems 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 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 100 kV or above.

> **Rationale for 4.2.6:** Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would applyonly to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation

5. Effective Date: See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[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 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 Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System 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, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System 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 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, and Table 3. (Part 1.2)

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.

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 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.

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 Protection System Maintenance Program for the Protection System 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.

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.

D. 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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, 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.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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) OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)	The responsible 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)	The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				• Annually perform maintenance on the greater of 5% of the segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15	The responsible entity failed to undertake efforts to correct greater

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	fewer identified Unresolved Maintenance Issues.	identified Unresolved Maintenance Issues.	identified Unresolved Maintenance Issues.	than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	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.	
2	December 19, 2013	FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014.	
TBD (balloted as 2(X)	TBD	Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[1]	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[1] 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**[1]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack
	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>
<tr><th colspan="3">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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="4">Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
Station dc supply voltage
Inspect:
For unintentional grounds</td></tr>
<tr><td>6 Calendar Months</td><td>Inspect:
Condition of all individual units by measuring battery cell/unit internal ohmic values.</td></tr>
<tr><td>18 Calendar Months</td><td>Verify:
Float voltage of battery charger
Battery continuity
Battery terminal connection resistance
Battery intercell or unit-to-unit connection resistance
Inspect:
Physical condition of battery rack</td></tr>
<tr><td>6 Calendar Months
-or-
3 Calendar Years</td><td>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.</td></tr>
</table>

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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) **Note:** Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS.	12 calendar years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5 and Table 3, 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 and Table 3 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	Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

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 of the Protection System Component population, 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 and Table 3 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 Protection System 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.
5. If the Components in a Protection System 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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

This version of PRC-005 contains revisions to the ~~a~~ a Applicability ~~section~~ of the Standard intended to clarify application of ~~the~~ its Requirements to Bulk Electric System dispersed power producing resources. PRC-005-3, a~~A~~ subsequent version of PRC-005, ~~PRC-005-3,~~ has been adopted by the NERC Board of Trustees and is pending regulatory approval. Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-005-2(X) for balloting purposes, may be filed for regulatory approval. The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is concurrently making technical revisions to PRC-005 in Project 2007-17.3 to address FERC directives. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-005 to dispersed power-producing resources.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Maintenance**

2. **Number:** PRC-005-~~2~~ X

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems 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 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 Special Protection System (SPS) for BES reliability.

> The only revisions made to this version of PRC-005 are revisions to section 4.2, 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.
>
> This version is labeled PRC-005-2(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-005 are in development to reflect the fact that applicability changes need apply for versions of the standard that are approved (PRC-005-2), pending regulatory approval (PRC-005-3), and in development in Project 2007-17.3. Depending on the timing of approvals of other versions, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

4.2.5 Protection Systems for the following BES generator Facilities~~ that are part of the BES, including~~ for generators not identified through Inclusion I4 of the BES definition:

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 for generator step-up transformers for generators that are part of the BES.

~~**4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).~~

~~**4.2.5.4**~~**4.2.5.3** Protection Systems 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.

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

4.2.6 Protection Systems 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 for ~~electrical equipment~~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 100 kV or above.

Rationale for 4.2.6: Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

5. Effective Date: See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[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 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.

> ***Component Type** - Any one of the five specific ~~elements~~elements of the Protection System*

1.2. Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.

> **Component** – *A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.*

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System 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, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

> ***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.*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System 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 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, and Table 3. (Part 1.2)

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.

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 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.

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 Protection System Maintenance Program for the Protection System 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.

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.

D. Compliance

1. Compliance Monitoring Process

~~1.1.~~ Compliance Enforcement Authority

1.1.

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

~~Regional Entity~~

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, 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.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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) OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)	The responsible 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)	The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				• Annually perform maintenance on the greater of 5% of the segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15	The responsible entity failed to undertake efforts to correct greater

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	fewer identified Unresolved Maintenance Issues.	identified Unresolved Maintenance Issues.	identified Unresolved Maintenance Issues.	than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	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.	
2	December 19, 2013	FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014.	
TBD (balloted as 2(X)	TBD	~~.~~Standard revised in Project 2014-01~~.~~	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[1]	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[1] 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**[1]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack
	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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) **Note:** Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS.	12 calendar years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5 and Table 3, 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 and Table 3 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	Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

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 of the Protection System Component population, 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 and Table 3 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.

> **Segment** – *Protection Systems or 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.*

> **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 and Table 3 which requires corrective action, or a 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 configuration errors, or Protection System application errors are not included in Countable Events.*

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Protection System 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.
5. If the Components in a Protection System 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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01, Standards Applicability for Dispersed Generation Resources Standards Drafting Team (DGR SDT) is posting proposed applicability changes to PRC-005-3 for comment and ballot. This draft contains the DGR SDT's recommended changes within the standard. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-005 to dispersed power-producing resources.

In a parallel effort, the Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) has posted draft 1 of PRC-005-X for a 45-day comment period, and ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System and Automatic Reclosing Maintenance**
2. **Number:** PRC-005-3(X)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing 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 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 Special Protection System (SPS) for BES reliability.

> The only revisions made to this version of PRC-005 are revisions to section 4.2, 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.
>
> This version is labeled PRC-005-3(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-005 are in development to reflect the fact that applicability changes need apply for versions of the standard that are approved (PRC-005-2), pending regulatory approval (PRC-005-3), and in development in Project 2007-17.3.

4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:

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 for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems 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.

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

4.2.6 Protection Systems 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 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 100 kV or above.

Rationale for 4.2.6: Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

4.2.7 Automatic Reclosing[1], including:

[1] Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 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 BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

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.

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 4.2.6.1 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 SPS specified in Section 4.2.4.

5. Effective Date: See Implementation Plan.

6. Definitions Used in this Standard: The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing 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 – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

Component – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

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, and Tables 4-1 through 4-2 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 or Automatic Reclosing configuration or application errors are not included in Countable Events.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[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 and Automatic Reclosing 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 and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing 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, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing 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 and Automatic Reclosing 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, and Table 4-1 through 4-2. (Part 1.2)

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.

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 and Automatic Reclosing 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.

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 Protection System Maintenance Program for the Protection System and Automatic Reclosing 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.

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.

D. 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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, 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.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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) OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)	The responsible 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)	The responsible 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). OR The responsible 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, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible 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).
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by 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
2	October 17, 2013	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	
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.
TBD (balloted as 2(X)	TBD	Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[2]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[2] 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**[2]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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>
<tr><th colspan="3">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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="2">Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
• Station dc supply voltage
Inspect:
• Electrolyte level
• For unintentional grounds</td></tr>
<tr><td>18 Calendar Months</td><td>Verify:
• Float voltage of battery charger
• Battery continuity
• Battery terminal connection resistance
• Battery intercell or unit-to-unit connection resistance
Inspect:
• 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
• Physical condition of battery rack</td></tr>
</table>

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, 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, and Tables 4-1 through 4-2 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>
<tr><th colspan="3">Table 3
Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td>Any unmonitored protective relay not having all the monitoring attributes of a category below.</td><td>6 Calendar Years</td><td>Verify that settings are as specified.
For non-microprocessor relays:
• Test and, if necessary calibrate.
For microprocessor relays:
• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.
• Verify acceptable measurement of power system input values.</td></tr>
<tr><td>Monitored microprocessor protective relay with the following:
• Internal self diagnosis and alarming (See Table 2).
• 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.
Alarming for power supply failure (See Table 2).</td><td>12 Calendar Years</td><td>Verify:
• Settings are as specified.
• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.
• Acceptable measurement of power system input values</td></tr>
<tr><td>Monitored microprocessor protective relay with preceding row attributes and the following:
• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).
• 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).
Alarming for change of settings (See Table 2).</td><td>12 Calendar Years</td><td>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</td></tr>
</table>

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	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 SPS 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 Relays that ARE an Integral Part of an SPS		
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 SPS (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 SPS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the SPS.
Control circuitry associated with Automatic Reclosing that is an integral part of an SPS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

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, and Tables 4-1 through 4-2 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.
5. 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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

~~The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is posting draft 1 of PRC-005-X for a 45-day comment period and ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).~~

~~This draft contains the technical content of the standard.~~ ~~A parallel effort in the~~ The Project 2014-01, Standards Applicability for Dispersed Generation Resources Standards Drafting Team (DGR SDT)~~,~~ ~~will~~ is posting proposed ~~an~~ applicability changes to ~~PRC-005-2 and~~ PRC-005-3 for comment and ballot. This draft contains the DGR SDT's recommended changes within ~~technical content of~~ the standard. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-005 to dispersed power-producing resources.

In a parallel effort, the Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) has posted draft 1 of PRC-005-X for a 45-day comment period, and ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System and Automatic Reclosing Maintenance**

2. **Number:** PRC-005-3(X)

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing 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 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 Special Protection System (SPS) for BES reliability.

> The only revisions made to this version of PRC-005 are revisions to section 4.2, 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.
>
> This version is labeled PRC-005-3(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-005 are in development to reflect the fact that applicability changes need apply for versions of the standard that are approved (PRC-005-2), pending regulatory approval (PRC-005-3), and in development in Project 2007-17.3.

4.2.5 Protection Systems for the following BES generator Facilities ~~that are part of the BES, including~~ for generators not identified through Inclusion I4 of the BES definition:

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 for generator step-up transformers for generators that are part of the BES.

~~**4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).~~

~~**4.2.5.4**~~**4.2.5.3** Protection Systems 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.

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

4.2.6 Protection Systems 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 for ~~electrical equipment~~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 100 kV or above.

Rationale for 4.2.6: Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

~~4.2.6~~4.2.7 Automatic Reclosing[1], including:

~~4.2.6.1~~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.

~~4.2.6.2~~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 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

~~4.2.6.3~~4.2.7.3 Automatic Reclosing applied as an integral part of an SPS specified in Section 4.2.4.

5. Effective Date: See Implementation Plan.

6. Definitions Used in this Standard: The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing 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 – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

Component – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit

[1] Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 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 BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

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, and Tables 4-1 through 4-2 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 or Automatic Reclosing configuration or application errors are not included in Countable Events.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[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 and Automatic Reclosing 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 and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing 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, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing 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 and Automatic Reclosing 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, and Table 4-1 through 4-2. (Part 1.2)

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.

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 and Automatic Reclosing 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.

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 Protection System Maintenance Program for the Protection System and Automatic Reclosing 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.

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.

D. 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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, 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.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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) OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)	The responsible 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)	The responsible 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). OR The responsible 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, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible 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).
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Component Type in accordance with their performance-based PSMP.	maintenance for a specific Component Type in accordance with their performance-based PSMP.	scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by 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
2	October 17, 2013	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	
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.
TBD (balloted as 2(X)	TBD	Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

<table>
<tr><th colspan="3">Table 1-1
Component Type - Protective Relay
Excluding distributed UFLS and distributed UVLS (see Table 3)</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval[2]</th><th>Maintenance Activities</th></tr>
<tr><td>Any unmonitored protective relay not having all the monitoring attributes of a category below.</td><td>6 Calendar Years</td><td>For all unmonitored relays:
Verify that settings are as specified
For non-microprocessor relays:
Test and, if necessary calibrate
For microprocessor relays:
Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.
Verify acceptable measurement of power system input values.</td></tr>
<tr><td>Monitored microprocessor protective relay with the following:
Internal self-diagnosis and alarming (see Table 2).
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.
Alarming for power supply failure (see Table 2).</td><td>12 Calendar Years</td><td>Verify:
Settings are as specified.
Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.
Acceptable measurement of power system input values.</td></tr>
</table>

[2] 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**[2]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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>
<tr><th colspan="3">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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="3">Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
• Station dc supply voltage
Inspect:
• For unintentional grounds</td></tr>
<tr><td>6 Calendar Months</td><td>Inspect:
• Condition of all individual units by measuring battery cell/unit internal ohmic values.</td></tr>
<tr><td>18 Calendar Months</td><td>Verify:
• Float voltage of battery charger
• Battery continuity
• Battery terminal connection resistance
• Battery intercell or unit-to-unit connection resistance
Inspect:
• Physical condition of battery rack</td></tr>
</table>

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, 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, and Tables 4-1 through 4-2 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	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	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 SPS 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 Relays that ARE an Integral Part of an SPS		
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 SPS (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 SPS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the SPS.
Control circuitry associated with Automatic Reclosing that is an integral part of an SPS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

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, and Tables 4-1 through 4-2 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.
5. 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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01, Standards Applicability for Dispersed Generation Resources Standards Drafting Team (DGR SDT) is posting proposed applicability changes to PRC-005-3 for comment and ballot. This draft contains the DGR SDT's recommended changes within the standard, which are intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-005 to dispersed power-producing resources.

In a parallel effort, the Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) has posted draft 1 of PRC-005-X for a 45-day comment period, and ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Protection System Maintenance Program (PSMP) — 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:

- 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.

See Section A.6, Definitions Used in this Standard*,* for additional definitions that are new or modified for use within this standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**
2. **Number:** **PRC-005-X**
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

4.1.4 Balancing Authority

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 Special Protection System (SPS) for BES reliability.

4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:

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.

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

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ection Systems 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 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 100 kV or above.

Rationale for 4.2.6: The Facilities listed that are applicable to dispersed power producing facilities are covered within 4.2.6. The intent is to NOT include the individual generating resources in the Protection System Maintenance Program, and as such the Protection Systems within the individual generating resources would not be within the scope of PRC-005. Only Protection Systems on equipment used in aggregating the dispersed BES generation from the point where those resources aggregate to greater than 75MVA to a common point of connection at 100kV would be included in the Protection System Maintenance Program, including the Protection Systems for those transformers used in aggregating generation.

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ic Reclosing[1], 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.

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 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

[1] 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 BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

4.2.6.3. Automatic Reclosing applied as an integral part of an SPS specified in Section 4.2.4.

5. **Effective Date:** See Implementation Plan.

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

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

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 two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Rationale for the deletion of part of the definition of Component: The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document.

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 4-2, 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 4-2, 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 Protection System Maintenance Program 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 4-2, 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.

Rationale for R3 part 3.1 and 3.1.1.: The SDT, upon further reflection, determined that the PRC-005-3 Implementation Plan actually included a requirement that entities with newly-identified Automatic Reclosing Components implement its PSMP for those Components, and therefore determined that it was more appropriate to include this information in the standard rather than the implementation plan.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall, except as provided in part 3.1, 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 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. For each newly-identified Automatic Reclosing Component following a notification under Requirement R6, each Transmission Owner, Generator Owner, and Distribution Provider shall perform maintenance activities or provide documentation of prior maintenance activities according to either 3.1.1 or 3.1.2.

3.1.1. Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component prior to the end of the third calendar year following the notification under Requirement R6; or

3.1.2. Provide documentation that the Automatic Reclosing Component was last maintained in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1, 4-2(a), and 4-2(b).

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.

Rationale for R4 part 4.1 and 4.1.1.: The SDT, upon further reflection, determined that the PRC-005-3 Implementation Plan actually included a requirement that entities with newly-identified Automatic Reclosing Components implement its PSMP for those Components, and therefore determined that it was more appropriate to include this information in the standard rather than the implementation plan.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall, except as provided in part 4.1, 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]*

4.1. For each newly-identified Automatic Reclosing Component following a notification under Requirement R6, each Transmission Owner, Generator Owner, and Distribution Provider shall perform maintenance activities or provide documentation of prior maintenance activities according to either 4.1.1 or 4.1.2.

4.1.1. Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component prior to the end of the third calendar year following the notification under Requirement R6; or

4.1.2. Provide documentation that the Automatic Reclosing Component was last maintained in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1, 4-2(a), and 4-2(b).

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 Protection System Maintenance Program 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.

Rationale for R6: The information addressed in Requirement R6 is necessary for Transmission Owners, Generator Owners, and Distribution Provides to accurately apply Section 4.2.7, Applicability. The Balancing Authority is the entity that maintains the information and should have the responsibility to provide this information to the applicable entities. The drafting team reconsidered the inclusion of the Balancing Authority and determined it is appropriate to include the requirement the standard. This requirement may be relocated to another standard during future reviews of standards for quality and content.

The periodicity was chosen to balance the needs of the Transmission Owner, Generator Owner, and Distribution Provider to obtain the information with the needs of the Balancing Authority to provide an accurate gross capacity (considering retirement or installation of generating units and/or changes in its Balancing Authority Area) in order to properly include Automatic Reclosing in a PSMP.

R6. Each Balancing Authority shall, at least once every calendar year with not more than 15 calendar months between notifications, notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Balancing Authority shall have dated documentation that it notified each Transmission Owner, Generator Owner, and Distribution Provider in accordance with Requirement R6. Examples of evidence may include, but are not limited to, copies of correspondence, such as e-mails or memoranda.

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, Distribution Provider, and Balancing Authority 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component, or all performances of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date, whichever is longer.

For Requirement R6, the Balancing Authority shall keep documentation for three calendar years that it provided information identifying the largest BES generating unit to the Transmission Owners, Generator Owners, and Distribution Providers in its Balancing Authority Area.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

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).	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). OR 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 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (part 1.2).	The entity failed to establish a PSMP. OR 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). OR The entity's PSMP failed to include applicable station batteries in a time-based program (part 1.1).
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.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
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 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per information from the Balancing Authority, the entity failed to	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 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per information from the Balancing	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 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per information from the Balancing	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 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	maintain 5% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	Authority, the entity failed to maintain more than 5% but 10% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	Authority, the entity failed to maintain more than 10% but 15% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	information from the Balancing Authority, the entity failed to maintain more than 15% of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.
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 Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain 5% or less of the total Components 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 Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 5% but 10% or less of the total Components 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 Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 10% but 15% or less of the total Components 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. For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 15% of the total Components 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	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Unresolved Maintenance Issues.	Issues.	Issues.
R6				The entity failed to notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area at least once every calendar year of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area. OR The entity had more than 15 calendar months between notifications to each Transmission Owner, Generator Owner, and Distribution Provider of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area.

D. Regional Variances

None.

E. Interpretations

None.

F. 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-X Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (April 2014)
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)

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)

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07	

Version	Date	Action	Change Tracking
		(Generator Requirements at the Transmission Interface).	
2	November 7, 2012	Adopted by 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
2	October 17, 2013	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…"	
TBD (balloted as X(X)	TBD	Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01, Standards Applicability for Dispersed Generation Resources Standards Drafting Team (DGR SDT) is posting proposed applicability changes to PRC-005-3 for comment and ballot. This draft contains the DGR SDT's recommended changes within the standard, which are intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-005 to dispersed power-producing resources.

In a parallel effort, the Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) has posted draft 1 of PRC-005-X for a 45-day comment period, and ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Protection System Maintenance Program (PSMP) — 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:

- 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.

See Section A.6, Definitions Used in this Standard*,* for additional definitions that are new or modified for use within this standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**
2. **Number: PRC-005-X**
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

   4.1.4 Balancing Authority

   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 Special Protection System (SPS) for BES reliability.

   4.2.5 Protection Systems for the following BES generator Facilities ~~that are part of the BES, including~~ for generators not identified through Inclusion I4 of the BES definition:

The only revisions made to this version of PRC-005 are revisions to section 4.2, 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.

This version is labeled PRC-005-~~2(~~X~~)~~ for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-005 are in development to reflect the fact that applicability changes need appl~~y~~ied for versions of the standard that are approved (PRC-005-2), pending regulatory approval (PRC-005-3), and in development in Project 2007-17.3. ~~-~~Depending on the timing of approvals of other versions, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

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 for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to 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.

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

4.2.6 Protection Systems 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 for ~~electrical equipment~~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 100 kV or above.

Rationale for 4.2.6: The Facilities listed that are applicable to dispersed power producing facilities are covered within 4.2.6. The intent is to NOT include the individual generating resources in the Protection System Maintenance Program, and as such the Protection Systems within the individual generating resources would not be within the scope of PRC-005. Only Protection Systems on equipment used in aggregating the dispersed BES generation from the point where those resources aggregate to greater than 75MVA to a common point of connection at 100kV would be included in the Protection System Maintenance Program, including the Protection Systems for those transformers used in aggregating generation.

~~4.2.6~~4.2.7 Automatic Reclosing[1], including:

~~4.2.6.1~~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.

~~4.2.6.2~~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 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3. Automatic Reclosing applied as an integral part of an SPS specified in Section 4.2.4.

[1] 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 BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

5. **Effective Date:** See Implementation Plan.

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

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

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 two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Rationale for the deletion of part of the definition of Component: The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document.

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 4-2, 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 4-2, 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 Protection System Maintenance Program 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 4-2, 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.

Rationale for R3 part 3.1 and 3.1.1.: The SDT, upon further reflection, determined that the PRC-005-3 Implementation Plan actually included a requirement that entities with newly-identified Automatic Reclosing Components implement its PSMP for those Components, and therefore determined that it was more appropriate to include this information in the standard rather than the implementation plan.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall, except as provided in part 3.1, 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 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. For each newly-identified Automatic Reclosing Component following a notification under Requirement R6, each Transmission Owner, Generator Owner, and Distribution Provider shall perform maintenance activities or provide documentation of prior maintenance activities according to either 3.1.1 or 3.1.2.

3.1.1. Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component prior to the end of the third calendar year following the notification under Requirement R6; or

3.1.2. Provide documentation that the Automatic Reclosing Component was last maintained in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1, 4-2(a), and 4-2(b).

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.

Rationale for R4 part 4.1 and 4.1.1.: The SDT, upon further reflection, determined that the PRC-005-3 Implementation Plan actually included a requirement that entities with newly-identified Automatic Reclosing Components implement its PSMP for those Components, and therefore determined that it was more appropriate to include this information in the standard rather than the implementation plan.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall, except as provided in part 4.1, 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]*

4.1. For each newly-identified Automatic Reclosing Component following a notification under Requirement R6, each Transmission Owner, Generator Owner, and Distribution Provider shall perform maintenance activities or provide documentation of prior maintenance activities according to either 4.1.1 or 4.1.2.

4.1.1. Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component prior to the end of the third calendar year following the notification under Requirement R6; or

4.1.2. Provide documentation that the Automatic Reclosing Component was last maintained in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1, 4-2(a), and 4-2(b).

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 Protection System Maintenance Program 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.

Rationale for R6: The information addressed in Requirement R6 is necessary for Transmission Owners, Generator Owners, and Distribution Provides to accurately apply Section 4.2.7, Applicability. The Balancing Authority is the entity that maintains the information and should have the responsibility to provide this information to the applicable entities. The drafting team reconsidered the inclusion of the Balancing Authority and determined it is appropriate to include the requirement the standard. This requirement may be relocated to another standard during future reviews of standards for quality and content.

The periodicity was chosen to balance the needs of the Transmission Owner, Generator Owner, and Distribution Provider to obtain the information with the needs of the Balancing Authority to provide an accurate gross capacity (considering retirement or installation of generating units and/or changes in its Balancing Authority Area) in order to properly include Automatic Reclosing in a PSMP.

R6. Each Balancing Authority shall, at least once every calendar year with not more than 15 calendar months between notifications, notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Balancing Authority shall have dated documentation that it notified each Transmission Owner, Generator Owner, and Distribution Provider in accordance with Requirement R6. Examples of evidence may include, but are not limited to, copies of correspondence, such as e-mails or memoranda.

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, Distribution Provider, and Balancing Authority 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component, or all performances of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date, whichever is longer.

For Requirement R6, the Balancing Authority shall keep documentation for three calendar years that it provided information identifying the largest BES generating unit to the Transmission Owners, Generator Owners, and Distribution Providers in its Balancing Authority Area.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

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).	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). OR 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 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (part 1.2).	The entity failed to establish a PSMP. OR 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). OR The entity's PSMP failed to include applicable station batteries in a time-based program (part 1.1).
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.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
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 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per information from the Balancing	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 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per	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 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per	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 4-2, and Table 5. For Automatic Reclosing Components added to a time-

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Authority, the entity failed to maintain 5% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	information from the Balancing Authority, the entity failed to maintain more than 5% but 10% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	information from the Balancing Authority, the entity failed to maintain more than 10% but 15% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 15% of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.
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 Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain 5% or less of the total Components 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 Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 5% but 10% or less of the total Components 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 Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 10% but 15% or less of the total Components 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. For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 15% of the total Components in accordance with their performance-based PSMP.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.
R6				The entity failed to notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area at least once every calendar year of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area. OR The entity had more than 15 calendar months between notifications to each Transmission Owner, Generator Owner, and Distribution Provider of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area.

D. Regional Variances

None.

E. Interpretations

None.

F. 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-X Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (April 2014)
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)

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)

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	

Version	Date	Action	Change Tracking
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (Generator Requirements at the Transmission Interface).	
2	November 7, 2012	Adopted by 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
2	October 17, 2013	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…"	
TBD (balloted as 4(X)	TBD	Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources
~~1a~~	~~September 26, 2011~~	~~FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)~~	
~~1.1a~~	~~February 1, 2012~~	~~Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility~~	~~Revision under Project 2010-07~~

Version	Date	Action	Change Tracking
~~1b~~	~~February 3, 2012~~	~~FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.~~	~~Project 2009-10 Interpretation~~
~~1.1b~~	~~April 23, 2012~~	~~Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.~~	~~Revision under Project 2010-07~~

Version	Date	Action	Change Tracking
~~1.1b~~	~~May 9, 2012~~	~~PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (Generator Requirements at the Transmission Interface).~~	
~~2~~	~~November 7, 2012~~	~~Adopted by 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~~
~~2~~	~~October 17, 2013~~	~~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~~	
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.
3.1	February 12, 2014	Approved by the Standards Committee	Errata changes to correct capitalization of defined terms

Version	Date	Action	Change Tracking
4			Project 2007-17.3 – Revised to address the FERC directive in Order No. 758 to include sudden pressure relays in maintenance programs.
TBD (balloted as ~~2~~(X))	TBD	~~.~~Standard revised in Project 2014-01~~.~~	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[2]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[2] 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**[2]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack

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 SPS, 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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, 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, and Tables 4-1 through 4-2 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	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
• 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). 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.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	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 SPS 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 Relays that ARE an Integral Part of an SPS		
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 SPS (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 SPS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the SPS.
Control circuitry associated with Automatic Reclosing that is an integral part of an SPS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 5 Maintenance Activities and Intervals for Sudden Pressure Relaying		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Control circuitry associated with Sudden Pressure Relaying from the fault pressure relay to the interrupting device trip coil(s).	12 Calendar Years	Verify all paths of the control circuits that are essential for proper operation of the Sudden Pressure Relaying.

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 4-2, 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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-2b. The standard previously was adopted by the NERC Board of Trustees on August 16, 2012, and approved by FERC on April 16, 2013. The intent of the revisions is to clarify application of Requirements R4 and R5 to BES Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-2b(X)
3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.
4. **Applicability**
   - **4.1.** Generator Operator.
   - **4.2.** Generator Owner.
5. **Effective Date:** The standard shall become effective on the date the standard is approved by an applicable government 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.

> The only revisions made to this version of VAR-002 are revisions to Requirements R3 and R4, 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.
>
> The revisions to the two Requirements were made to VAR-002-2b, which is the currently enforceable version of VAR-002. VAR-002-3 is pending regulatory approval, and depending on the timing of the approval of VAR-002-3, NERC may request approval of this interim version of the standard in order to provide regulatory certainty for entities as the revised definition of BES is being implemented. This interim version is labeled VAR-002-2b(X) for balloting purposes.

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up[1] or shutdown[2] mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

- That the generator is not being operated in the automatic voltage control mode for a reason other than start-up or shutdown.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within applicable Facility Ratings[4]) as directed by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

- Reporting of status or capability changes is not applicable to the individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

Rationale for R3 Exclusion:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R3.1 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide real time data as directed by the TOP.

[3] The voltage or Reactive Power schedule is a target value communicated by the Transmission Operator to the Generator Operator establishing a tolerance band within which the target value is to be maintained during a specified period.

[4] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this may lead to a change in the associated Facility Ratings.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

4.1. For generator step-up transformers and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

4.1.1. Tap settings.

4.1.2. Available fixed tap ranges.

4.1.3. Impedance data.

4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

Rationale for Footnote 5 in Requirement R4, Part 4.1: The Transmission Operator / Transmission Provider needs to review tap settings on the main transformers that connect the generation to the high voltage system. The Transmission Operator / Transmission Provider must assure that the collector system (typically 34.5 kV) voltage coordinates with the voltage set-points and tolerance bands established by the Transmission Operator / Transmission. The portion of the collector system that aggregates 75 MVA or less of resources is excluded under I4 and the individual unit step-up transformers primarily affect the collector system, so it should also be excluded and left to the Generator Owner to design and manage based on the secondary voltages expected on the collector system.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1. If a generator is being started up or shut down with the automatic voltage control off and no notification of the automatic voltage regulator status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode. Such evidence must include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's direction as identified in Requirement 2.1 and Requirement 2.2.

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[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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.

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1.2. 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 Generator Operator shall maintain evidence needed for Measure 1 through Measure 4 and Measure 7 for the current and previous calendar year.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measures 5 and 6)

The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The responsible entity did not operate each generator in the automatic voltage control mode and failed to notify the Transmission Operator as identified in R1.
R2.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for up to and including 45 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 45 minutes up to and including 60 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator. OR The Generator Operator failed to provide an explanation of why the voltage schedule could not be met.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 60 minutes up to and including 75 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 75 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator and the Generator Operator failed to provide an explanation of why the voltage schedule could not be met.
R3.	N/A	N/A	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in either R3.1 or R3.2	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in both R3.1 and R3.2

R4.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner one of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 30, but less than or equal to 35 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner two of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 35, but less than or equal to 40 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner three of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 40, but less than or equal to 45 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner any of the types of data as specified in R4.1.1 and R 4.1.2 and 4.1.3 and 4.1.4 OR The information was provided in more than 45 calendar days of the request.
R5.	N/A	N/A	N/A	The responsible entity failed to ensure that transformer tap positions were changed according to the specifications provided by the Transmission Operator when said actions would not have violated safety, an equipment rating, a regulatory requirement, or a statutory requirement.
R5.1.	N/A	N/A	N/A	The responsible entity failed to notify the Transmission Operator and to provide technical justification.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 — Interpretation of Requirements R1 and R2 (August 1, 2007).

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	January 16, 2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	October 29, 2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	March 3, 2009	Added Appendix 2 **–** Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	TBD	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4.	Revised
2b	August 16, 2012	Adopted by Board of Trustees	
2b	April 16, 2013	FERC Order issued approving VAR-002-2b	
2b(X)	TBD	Interim version to clarify applicability of two Requirements to BES dispersed power producing resources. Revised in Project 2014-01.	Revised

Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

Appendix 2

Interpretation of VAR-002-1a

Request:

VAR-002 — Generator Operation for Maintaining Network Voltage Schedules, addresses the generator's provision of voltage and VAR control. Confusion exists in the industry and regions as to which requirements in this standard apply to Generator Operators that operate generators that do not have automatic voltage regulation capability.

The Standard's requirements do not identify the subset of generator operators that need to comply – forcing some generator operators that do not have any automatic voltage regulation capability to demonstrate how they complied with the requirements, even when they aren't physically able to comply with the requirements. Generator owners want clarification to verify that they are not expected to acquire AVR devices to comply with the requirements in this standard.

Many generators do not have automatic voltage regulators and do not receive voltage schedules. These entities are at a loss as to how to comply with these requirements and are expending resources attempting to demonstrate compliance with these requirements. A clarification will avoid challenges and potential litigation stemming from sanctions and penalties applied to entities that are being audited for compliance with this standard, but who do not fall within the scope or intent of the standard itself.

Please identify which requirements apply to generators that do not operate generators equipped with AVRs.

Response: All the requirements and associated subrequirements in VAR-002-1a apply to Generator Owners and Generator Operators that own or operate generators whether equipped with an automatic voltage regulator or not. The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. A generator that is not equipped with an automatic voltage regulator results in a functionally equivalent condition to a generator equipped with an automatic voltage regulator that is out of service due to maintenance or failure.

There are no requirements in the standard that require a generator to have an automatic voltage regulator, nor are there any requirements for a Generator Owner to modify its generator to add an automatic voltage regulator. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-2b. The standard previously was adopted by the NERC Board of Trustees on August 16, 2012, and approved by FERC on April 16, 2013. The intent of the revisions is to clarify application of Requirements R4 and R5 to BES Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**

2. **Number:** VAR-002-2b(X)

> The only revisions made to this version of VAR-002 are revisions to Requirements R3 and R4, 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.
>
> The revisions to the two Requirements were made to VAR-002-2b, which is the currently enforceable version of VAR-002. VAR-002-3 is pending regulatory approval, and depending on the timing of the approval of VAR-002-3, NERC may request approval of this interim version of the standard in order to provide regulatory certainty for entities as the revised definition of BES is being implemented. This interim version is labeled VAR-002-2b(X) for balloting purposes.

3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.

4. **Applicability**

   4.1. Generator Operator.

   4.2. Generator Owner.

5. **Effective Date:** The standard shall become effective on the date the standard is approved by an applicable government 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~~In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees approval~~.

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up[1] or shutdown[2] mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in the automatic voltage control mode for a reason other than start-up or shutdown.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within applicable Facility Ratings[4]) as directed by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

- Reporting of status or capability changes is not applicable to the individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

Rationale for R3 Exclusion:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R3.1 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide real time data as directed by the TOP.

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[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

[3] The voltage or Reactive Power schedule is a target value communicated by the Transmission Operator to the Generator Operator establishing a tolerance band within which the target value is to be maintained during a specified period.

[4] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this may lead to a change in the associated Facility Ratings.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

4.1. For generator step-up transformers and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

4.1.1. Tap settings.

4.1.2. Available fixed tap ranges.

4.1.3. Impedance data.

4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

Rationale for Footnote 5 in Requirement R4, Part 4.1:

The Transmission Operator / Transmission Provider needs to review tap settings on the main transformers that connect the generation to the high voltage system. The Transmission Operator / Transmission Provider must assure that the collector system (typically 34.5 kV) voltage coordinates with the voltage set-points and tolerance bands established by the Transmission Operator / Transmission. The portion of the collector system that aggregates 75 MVA or less of resources is excluded under I4 and the individual unit step-up transformers primarily affect the collector system, so it should also be excluded and left to the Generator Owner to design and manage based on the secondary voltages expected on the collector system.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1. If a generator is being started up or shut down with the automatic voltage control off and no notification of the automatic voltage regulator status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode. Such evidence must include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's direction as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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.

~~For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.~~

~~For functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority~~.

1.2. 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 Generator Operator shall maintain evidence needed for Measure 1 through Measure 4 and Measure 7 for the current and previous calendar year.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measures 5 and 6)

The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The responsible entity did not operate each generator in the automatic voltage control mode and failed to notify the Transmission Operator as identified in R1.
R2.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for up to and including 45 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 45 minutes up to and including 60 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator. OR The Generator Operator failed to provide an explanation of why the voltage schedule could not be met.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 60 minutes up to and including 75 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 75 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator and the Generator Operator failed to provide an explanation of why the voltage schedule could not be met.
R3.	N/A	N/A	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in either R3.1 or R3.2	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in both R3.1 and R3.2

R4.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner one of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 30, but less than or equal to 35 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner two of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 35, but less than or equal to 40 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner three of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 40, but less than or equal to 45 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner any of the types of data as specified in R4.1.1 and R 4.1.2 and 4.1.3 and 4.1.4 OR The information was provided in more than 45 calendar days of the request.
R5.	N/A	N/A	N/A	The responsible entity failed to ensure that transformer tap positions were changed according to the specifications provided by the Transmission Operator when said actions would not have violated safety, an equipment rating, a regulatory requirement, or a statutory requirement.
R5.1.	N/A	N/A	N/A	The responsible entity failed to notify the Transmission Operator and to provide technical justification.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 — Interpretation of Requirements R1 and R2 (August 1, 2007).

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	January 16, 2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	October 29, 2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	March 3, 2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	TBD	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4.	Revised
2b	August 16, 2012	Adopted by Board of Trustees	
2b	April 16, 2013	FERC Order issued approving VAR-002-2b	
2b(X)	TBD	Interim version to clarify applicability of two Requirements to BES dispersed power producing resources. Revised in Project 2014-01.	Revised

Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

Appendix 2

Interpretation of VAR-002-1a

Request:

VAR-002 — Generator Operation for Maintaining Network Voltage Schedules, addresses the generator's provision of voltage and VAR control. Confusion exists in the industry and regions as to which requirements in this standard apply to Generator Operators that operate generators that do not have automatic voltage regulation capability.

The Standard's requirements do not identify the subset of generator operators that need to comply – forcing some generator operators that do not have any automatic voltage regulation capability to demonstrate how they complied with the requirements, even when they aren't physically able to comply with the requirements. Generator owners want clarification to verify that they are not expected to acquire AVR devices to comply with the requirements in this standard.

Many generators do not have automatic voltage regulators and do not receive voltage schedules. These entities are at a loss as to how to comply with these requirements and are expending resources attempting to demonstrate compliance with these requirements. A clarification will avoid challenges and potential litigation stemming from sanctions and penalties applied to entities that are being audited for compliance with this standard, but who do not fall within the scope or intent of the standard itself.

Please identify which requirements apply to generators that do not operate generators equipped with AVRs.

Response: All the requirements and associated subrequirements in VAR-002-1a apply to Generator Owners and Generator Operators that own or operate generators whether equipped with an automatic voltage regulator or not. The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. A generator that is not equipped with an automatic voltage regulator results in a functionally equivalent condition to a generator equipped with an automatic voltage regulator that is out of service due to maintenance or failure.

There are no requirements in the standard that require a generator to have an automatic voltage regulator, nor are there any requirements for a Generator Owner to modify its generator to add an automatic voltage regulator. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-3. The standard previously was adopted by the NERC Board of Trustees in May 2014 and is pending regulatory approval. The intent of the revisions is to clarify application of Requirements R4 and R5 to Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.	Revised
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised
3	5/7/2014	Adopted by NERC Board of Trustees	
4	TBD	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised

Definitions of Terms Used in the Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

When this standard has received ballot approval, the text boxes within the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

The only revisions made to this version of VAR-002 are revisions to Requirements R4 and R5, 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.

The revisions to the two Requirements were made to VAR-002-3, which was approved by its ballot pool and adopted by the NERC Board in May 2014, VAR-002-3 is currently pending regulatory approval.

1. **Title: Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Generator Operator
   - **4.2.** Generator Owner
5. **Effective Dates**

   The standard shall become effective on the later of the effective date of VAR-002-3, or the date the standard VAR-002-4 is approved by an applicable government 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. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within each generating Facility's capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive

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[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.
[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.
[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.
[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of reactive capability changes is not applicable to the individual for dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for Exclusion in R4:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide real time data as directed by the TOP.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

R5. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

5.1. For generator step-up transformers and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

R7. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

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 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19,~~.~~ 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-3. The standard previously ~~, which~~ was adopted by the NERC Board of Trustees in May 2014 and is pending regulatory approval. The intent of the revisions is to clarify application of Requirements R4 and R5 to ~~BES~~ Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.	Revised
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised
3	5/7/2014	Adopted by NERC Board of Trustees	
4	TBD	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised

Definitions of Terms Used in the Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

When this standard has received ballot approval, the text boxes within the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Generator Operator
   - **4.2.** Generator Owner

> The only revisions made to this version of VAR-002 are revisions to Requirements R4 and R5, 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.
>
> The revisions to the two Requirements were made to VAR-002-3, which was approved by its ballot pool and adopted by the NERC Board in May 2014, VAR-002-3 is currently pending regulatory approval.

5. **Effective Dates**

   The standard shall become effective on the later of the effective date of VAR-002-3, or the date the standard VAR-002-4 is approved by an applicable government 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~~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, VAR-002-3 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. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within each generating Facility's capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

~~**R7.**~~

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of reactive capability changes is not applicable to the individual for dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for Exclusion in R4:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide real time data as directed by the TOP.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

~~R4.~~R5. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~4.1.~~5.1. For generator step-up transformers and auxiliary transformers[5] with primary

Rationale for Footnote 5 in Requirement R5, Part 5.1: The Transmission Operator / Transmission Provider needs to review tap settings on the main transformers that connect the generation to the high voltage system. The Transmission Operator / Transmission Provider must assure that the collector system (typically 34.5 kV) voltage coordinates with the voltage set-points and tolerance bands established by the Transmission Operator / Transmission. The portion of the collector system that aggregates 75 MVA or less of resources is excluded under I4 and the individual unit step-up transformers primarily affect the collector system, so it should also be excluded and left to the Generator Owner to design and manage based on the secondary voltages expected on the collector system.

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

voltages equal to or greater than the generator terminal voltage:

~~4.1.1.~~5.1.1. Tap settings.

~~4.1.2.~~5.1.2. Available fixed tap ranges.

~~4.1.3.~~5.1.3. Impedance data.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

~~R5.~~R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

~~5.1.~~6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

~~R8.~~R7. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

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 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

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.

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Implementation Plan

Project 2014-01 Standards Applicability for Dispersed Power Producing Resources
PRC-005-2(X)

The standard numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to BOT adoption.

Standards Involved

Approval:

- PRC-005-2(X) – Protection System Maintenance

Retirement:

- PRC-005-2 – Protection System Maintenance

Prerequisite Approvals:

N/A

Background:

In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk-Power System.

Reliability Standard PRC-005-2, with its associated Implementation Plan, was adopted by the NERC Board of Trustees on November 7, 2012. The SDT has revised the applicability section of PRC-005-2 to align with the revised definition of "Bulk Electric System" in the event that this version of PRC-005 is mandatory and enforceable on the effective date of the revised definition of "Bulk Electric System."

General Considerations:

PRC-005-2(X) is proposed for approval to align the applicability section of PRC-005-2 with the revised definition of "Bulk Electric System." PRC-005-2 may already be retired pursuant to an implementation plan of a successor version of PRC-005 by the time the revised definition of "Bulk Electric System" becomes effective. If this occurs, PRC-005-2(X) will not go into effect.

Effective Date
PRC-005-2(X) shall become effective on the later of the effective date of the revised definition of Bulk Electric System or the first day following the effective date of PRC-005-2.

Retirement of Existing Standards:
PRC-005-2 shall be retired at midnight of the day immediately prior to the effective date of PRC-005-2(X) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan
All aspects of the Implementation Plan for PRC-005-2 will remain applicable to PRC-005-2(X) and are incorporated here by reference.

Cross References
The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-005-2 is available here.

Implementation Plan

Project 2014-01 Standards Applicability for Dispersed Power Producing Resources
PRC-005-3(X)

The standard numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to BOT adoption.

Standards Involved

Approval:

- PRC-005-3(X) – Protection System and Automatic Reclosing Maintenance

Retirement:

- PRC-005-2(X) – Protection System Maintenance
- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Prerequisite Approvals

N/A

Background

In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk-Power System.

Reliability Standard PRC-005-3, with its associated Implementation Plan, was adopted by the NERC Board of Trustees on November 7, 2013. The SDT has revised the applicability section of PRC-005-3 to align with the revised definition of "Bulk Electric System" in the event that this version of PRC-005 is mandatory and enforceable on the effective date of the revised definition of "Bulk Electric System."

General Considerations

PRC-005-3(X) is proposed for approval to align the applicability section of PRC-005-3 with the revised definition of "Bulk Electric System." PRC-005-3 may already be retired pursuant to an Implementation Plan of a successor version of PRC-005 by the time the revised definition of "Bulk Electric System" becomes effective. If this occurs, PRC-005-3(X) will not go into effect.

Effective Date

PRC-005-3(X) shall become effective on the later of the effective date of the revised definition of Bulk Electric System or the first day following the effective date of PRC-005-3.

Retirement of Existing Standards

PRC-005-3 shall be retired at midnight of the day immediately prior to the effective date of PRC-005-3(X) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

PRC-005-3(X) only modifies the applicability for PRC-005-3. All aspects of the Implementation Plan for PRC-005-3 will remain applicable to PRC-005-3(X) and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-005-3 is available here.

Implementation Plan

Project 2014-01 Standards Applicability for Dispersed Power Producing Resources
PRC-005-X(X)

The standard numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to BOT adoption.

Standards Involved
Approval:

- PRC-005-X(X) – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Retirement:

- PRC-005-3(X) – Protection System and Automatic Reclosing Maintenance
- PRC-005-X – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Prerequisite Approvals:
N/A

Background:
In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk-Power System.

Reliability Standard PRC-005-X has concluded a 45-day comment and ballot period to address sudden pressure relays. The SDT has revised the applicability section of PRC-005-X to align with the revised definition of "Bulk Electric System" in the event that this version of PRC-005 is mandatory and enforceable on the effective date of the revised definition of "Bulk Electric System."

General Considerations:
PRC-005-X(X) is proposed for approval to align the applicability section of PRC-005-X with the revised definition of "Bulk Electric System." PRC-005-X may already be retired pursuant to an Implementation

Plan of a successor version of PRC-005 by the time the revised definition of "Bulk Electric System" becomes effective. If this occurs, PRC-005-X(X) will not go into effect.

Effective Date

PRC-005-X(X) shall become effective on the later of the effective date of the revised definition of Bulk Electric System or the first day following the effective date of PRC-005-X.

Retirement of Existing Standards

PRC-005-X shall be retired at midnight of the day immediately prior to the effective date of PRC-005-X(X) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

PRC-005-X(X) only modifies the applicability for PRC-005-X. All aspects of the Implementation Plan for PRC-005-X will remain applicable to PRC-005-X(X) and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.[1]

The Implementation Plan for PRC-005-X is available here.[2]

1

2

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Implementation Plan

Dispersed Generation Resources
VAR-002-2b(X)

Standards Involved

Approval:

- VAR-002-2b(X) – Generator Operation for Maintaining Network Voltage Schedules

Retirement or Supersede:

- VAR-002-2b – Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including VAR-002, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk-Power System.

Effective Date

VAR-002-2b(X) shall become effective on the date the standard is approved by an applicable government 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.

Retirement of Existing Standards:

The existing standard VAR-002-2b shall be retired at midnight of the day immediately prior to the effective date of VAR-002-2b(X).

Implementation Plan
Dispersed Generation Resources
VAR-002-4

Standards Involved
Approval:

- VAR-002-4 – Generator Operation for Maintaining Network Voltage Schedules

Retirement or Supersede:

- VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals:
N/A

Background:
In light of the adoption of a revised “Bulk Electric System” definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised “Bulk Electric System” definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk-Power System.

Effective Date
VAR-002-4 shall become effective on the later of the effective date of VAR-002-3, or the date the VAR-002-4 is approved by an applicable government 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.

Retirement of Existing Standards:
Proposed VAR-002-3, shall be retired at midnight of the day immediately prior to the effective date of VAR-002-4.

Unofficial Comment Form

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standards. The electronic comment form must be completed by **July 28, 2014**.

If you have questions please contact Sean Cavote or by telephone at 404.446.9697.

All documents for this project are available on the project page.

Background Information

This posting solicits formal comments on two of three Project 2014-01 Dispersed Generation Resources (DGR) "high-priority" Reliability Standards as identified in the draft white paper (White Paper) prepared by the Project 2014-01 (Project) drafting team (DGR SDT).

The goal of the Project is to ensure that the Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System, as the characteristics of operating dispersed power producing resources can be unique. In light of the revised Bulk Electric System (BES) definition approved by the Federal Energy Regulatory Commission in 2014, the intent of this Project is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources where the status quo does not create a reliability gap.

The DGR SDT performed a review of all standards that apply to GOs and GOPs and categorized how each standard should be applied to dispersed power producing resources to accomplish the reliability purpose of the standard. The DGR SDT developed the White Paper to explain its approach, which was posted on April 17, 2014 for an informal comment period.[1] The industry feedback received on the White Paper allowed the DGR SDT to refine its approach and finalize recommended revisions to the standards. As part of this review the DGR SDT determined that there are three high-priority standards in which immediate attention is required to provide direction to industry stakeholders as soon as feasible regarding how to appropriately direct compliance related preparations:

- PRC-004-2.1a;[2]
- PRC-005; and
- VAR-002.

[1] The current version of the White Paper can be downloaded on the Project web page at http://www.nerc.com/pa/Stand/Pages/Project-2014-01-Standards-Applicability-for-Dispersed-Generation-Resources.aspx.

[2] The DGR SDThas prepared applicability revisions for relevant versions of PRC-004 – the third high-priority standard – which will be posted for ballot and comment separately after the current comment period and ballot of that standard in Project 2010-05.1 ends.

Because each of the "high-priority" standards has recently been revised or is undergoing revision in another current project, the DGR SDT has developed revisions to multiple versions of each standard to allow for different possibilities in the timing of regulatory approvals. When the revisions are being applied to a version that is not the last approved version of the standard or to a version that is pending regulatory approval, the version is noted with "(X)" after it. For example, this posting includes PRC-005-2(X), which proposes applicability changes to PRC-005-2, as well as PRC-005-3(X), which proposes applicability changes to PRC-005-3. Please note that any versions of the standards posted under this project with an "X" suffix will have a version number applied at a later time in order to manage sequencing of version numbers. The intent of balloting the recommended applicability revisions separately from the technical changes that are ongoing in other projects is to provide flexibility to allow approved applicability revisions to move forward on an expedited timeline as needed to support implementation of the revised definition of BES.

The DGR SDT responded to industry comments as contained in its Consideration of Comments, which is included with this posting, along with the DGR SDT's response to comments on the original Standards Authorization Request (SAR) that defines the scope of this Project.

The DGR SDT continues to coordinate with other NERC Reliability Standards projects currently under development to ensure continuity and to develop a posting strategy that ensures all applicability changes approved by ballot are filed and implemented as quickly as possible without adversely impacting other projects. The DGR SDT Coordination Plan included with this posting details that coordination.

Summary of Proposed Changes

The DGR's recommended changes are limited to revising the applicability of the relevant versions of PRC-005 and VAR-002 to appropriately exclude certain dispersed power producing resources from the standards. Although the redlined versions of the standards included with this posting contain changes that appear structurally different, the substance of the changes in each respective set of standards is the same.

The drafting team has posted the following standards, along with corresponding implementation plans:

- PRC-005-2(X) (clean and redlined against PRC-005-2)
- PRC-005-3(X) (clean and redlined against PRC-005-3, which is pending regulatory approval)
- PRC-005-X(X) (clean and redlined against the latest draft of PRC-005-X from Project 2007-17.1)
- VAR-002-2b(X) (clean and redlined against currently enforceable VAR-002-2b)
- VAR-002-4 (clean and redlined against VAR-002-3, which is pending regulatory approval)
  In addition, the drafting team has posted the following supporting documents.
- SAR

- White Paper[3]
- DGR SDT Response to SAR Comments
- DGR SDT Response to White Paper Comments
- Draft DGR SDT Coordination Plan

Please note that the DGR SDT has not revised the Violation Risk Factors (VRFs) or Violation Severity Levels (VSLs) associated with the subject standards because the proposed revisions do not change the reliability intent or impact of any of the requirements. If the applicability recommendations are approved by industry, the DGR SDT's intent is that the VRFs and VSLs for each requirement would be unchanged from those either previously approved (for currently enforceable versions of standards or those pending regulatory approval) or would be developed by the drafting team responsible for revising technical content (for those versions of standards currently in development in another standards project).

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you agree with the revisions made in proposed PRC-005-2(X) to clarify applicability of PRC-005-2 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

2. Do you agree with the revisions made in proposed PRC-005-3(X) to clarify applicability of PRC-005-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

3. Do you agree with the revisions made in proposed PRC-005-X(X) to clarify applicability of PRC-005-X (the version of PRC-005 containing revisions to address Sudden Pressure relays, being developed in

[3] Please note that the DGR SDT is currently revising the White Paper and will post the next version when it is finalized. However, the DGR SDT's response to White Paper comments identifies areas of the White Paper the DGR SDT intends to clarify.

Project 2007-17.1) to dispersed power-producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

Yes:

No:

Comments:

4. Do you agree with the revisions made in proposed VAR-002-2b(X) to clarify applicability of VAR-002-2b to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

5. Do you agree with the revisions made in proposed VAR-002-4 to clarify applicability of VAR-002-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

6. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

   Yes:

   No:

   Comments:

Project 2014-01 Dispersed Generation Resources

DRAFT Plan for Standards Drafting Team (SDT) Coordination and Balloting Multiple Versions of Standards | June 12, 2014

Background

Pursuant to the Standards Authorization Request for this project posted on November 20, 2014, the Project 2014-01 Dispersed Generation Resources (DGR) SDT proposes to modify PRC-004-2.1a, PRC-004-3, PRC-005-2, PRC-005-3, PRC-005-X, VAR-002-2b, and VAR-002-3 to account for the unique characteristics of dispersed power producing resources. As the DGR SDT has explained in the White Paper it has developed, the DGR SDT has classified each of these standards as high-priority standards requiring applicability changes as soon as practicable.

Because each of the high-priority standards has recently been revised or is undergoing revision in another active standard development project, the DGR SDT has developed revisions to multiple versions of each standard to allow for different possibilities in the timing of regulatory approvals. Specifically, two of the three standards identified by the DGR SDT as high priority (PRC-004 and PRC-005) are being revised by other projects. NERC and the DGR SDT recognize that developing multiple versions of the same standard in different projects may be confusing; however, developing and balloting the recommended DGR applicability revisions separately from the technical changes that are ongoing in other active standard development projects provides flexibility in effectuating applicability revisions on an expedited timeline as needed to support implementation of the revised definition of the Bulk Electric System. The DGR project is being carefully coordinated with other active standard development projects with careful consideration of the period of time various versions of each standard may be in effect.

When DGR revisions are applied to a standard version that is not the last approved version of the standard or to a standard version that may be superseded by another version in active standard development outside the DGR project, the version is noted with “(X)” after it. For example, the DGR SDT is developing PRC-005-2(X), which proposes applicability changes to PRC-005-2, as well as PRC-005-3(X), which proposes applicability changes to PRC-005-3. Please note that NERC will apply at a later time the appropriate version numbers to standard versions containing an “X” suffix in order to effectively manage sequencing of version numbers in these projects.

PRC-004 DGR Applicability Modifications

(*Note that since PRC-004-3 is posted for a 45-day comment period and additional ballot through June 30, 2014, NERC is deferring posting DGR applicability recommendations on PRC-004 until after that ballot closes.)*

PRC-004-2.1a (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) is FERC-approved and has been enforceable since November 25, 2013. PRC-004-3 is in active standard development in Project 2010-05.1 and may supersede PRC-004-2.1a; however, until PRC-004-3 is completed, approved by applicable government authorities, and becomes enforceable, there may be a need for revisions to tailor the applicability of PRC-004-2.1a, which the DGR SDT intends to ballot as PRC-004-2.1a(X). The proposed implementation period for PRC-004-3 is 12 months.

PRC-004-3 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) is currently in active standard development in Project 2010-05.1 Protection System Misoperations. The DGR SDT and the Protection System Misoperations SDT are coordinating regarding changes to the applicability of PRC-004. The DGR

SDT intends to ballot proposed applicability revisions to PRC-004-3 as PRC-004-3(X). Depending on the timing of completion of Project 2010-05.1 relative to Project 2014-01, both PRC-004-2.1a(X) and PRC-004-3(X) may be needed.

PRC-005 DGR Applicability Modifications

PRC-005-2 (Protection System Maintenance): PRC-005-2 is FERC-approved and will become enforceable on April 1, 2015. PRC-005-2 has a 12-year phased-in implementation period and may be enforceable for a period of time before PRC-005-3 becomes enforceable after approval by the applicable government authorities. Therefore, the DGR SDT is balloting proposed revisions to the applicability of PRC-005-2 as PRC-005-2(X).

PRC-005-3 (Protection System and Automatic Reclosing Maintenance): PRC-005-3 was adopted by the NERC Board of Trustees (Board) on November 7, 2013 and filed with the applicable governmental authorities on February 14, 2014. Upon regulatory approval, PRC-005-3 will supersede PRC-005-2, and according to its proposed implementation plan, will continue the 12-year implementation period for components included in PRC-005-2. Therefore, the DGR SDT is balloting proposed revisions to the applicability of PRC-005-3 as PRC-005-3(X).

PRC-005-X (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance): PRC-005-X is currently in an active standards development project. A ballot for PRC-005-X concluded on June 3, 2014 but did not receive sufficient affirmative votes for approval. The PRC-005-X SDT will consider comments and, if needed, make revisions to the standard. Language to clarify the applicability of the requirements of PRC-005-X was agreed to by both SDTs, and is being balloted in the DGR project as PRC-005-X(X). Depending on the timing of the completion of the DGR project relative to Project 2007-17.3, NERC will determine the appropriate approach to filing applicability changes approved by balloters and adopted by the Board.

VAR-002 DGR Applicability Modifications

VAR-002-2b (Generator Operation for Maintaining Network Voltage Schedules) is FERC-approved and has been enforceable since July 1, 2013. A successor version, VAR-002-3, is pending regulatory approval and has a proposed implementation period of one quarter. Depending on the time of regulatory approvals of VAR-002-3, VAR-002-2b may remain in effect. Therefore, the DGR SDT is balloting proposed revisions to clarify the applicability of VAR-002-2b as VAR-002-2b(X).

VAR-002-3 (Generator Operation for Maintaining Network Voltage Schedules) was adopted by the Board on May 7, 2014 and filed with the applicable governmental authorities on June 10, 2014. No other version of VAR-002 is in active standard development outside the DGR project. Therefore, the DGR SDT is balloting proposed revisions to VAR-002-3 as VAR-002-4.

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation		
Date Submitted:	10/1/2013		
SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
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. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard. **PRC-005-2** Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply. **FAC-008-3** For dispersed generation, it is unclear if in FAC-008-3 the term "main step up transformer" refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information
Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES “Facilities,” and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels. **PRC-023-3/PRC-025-1** In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements. **PRC-004-2** There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above. **VAR-002-2** Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard. **General review of IROs, MODs, PRCs, TOPs** IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

Reliability Functions		
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2014-01 Applicability for Dispersed Generation Resources Standards

PRC-005-2(X), PRC-005-3(X), PRC-005-X(X), VAR-002-2b(X), VAR-002-4

Ballots Now Open through July 28, 2014

Now Available

Ballots for five **Project 2014-01 Dispersed Generation Resources Reliability Standards, (PRC-005-2(X), PRC-005-3(X), PRC-005-X(X), VAR-002-2b(X), and VAR-002-4)** are open through **8 p.m. Eastern on Monday, July 28, 2014.**

If you have questions please contact Sean Cavote (via email) or by telephone at (404) 446-9697.

Background information for this project can be found on the project page.

Instructions for Balloting
Members of the ballot pools associated with this project may log in and submit their votes for the standards by clicking here.

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Formal Comment Period Now Open through July 28, 2014
Ballot Pools Forming Now through July 11, 2014

Now Available

A 45-day posting to solicit formal comments on two of three Project 2014-01 Dispersed Generation Resources "high-priority" Reliability Standards as identified in the draft white paper prepared by the Project 2014-01 drafting team is open through **8 p.m. Eastern on Monday, July 28, 2014.**

If you have questions please contact Sean Cavote (via email) or by telephone at (404) 446-9697.

Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments on the standards and implementation plans. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Instructions for Joining Ballot Pools

Ballot pools are currently being formed. Registered Ballot Body members must join the ballot pools to be eligible to cast ballots. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pools may communicate with one another by using their "ballot pool list servers." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

bp-2014-01_PRC-005-2(X)_in@nerc.com

bp-2014-01_PRC-005-3(X)_in@nerc.com

bp-2014-01_PRC-005-X(X)_in@nerc.com

bp-2014-01_VAR-002-4_in@nerc.com

bp-2014-01_VAR-002-2b(X_in@nerc.com

bp-PRC005_VAR002_DGR_IP_in@nerc.com

Next Steps
A ballot period for the standards and implementation plans will be conducted **July 18-28, 2014.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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bp-2014-01_PRC-005-2(X)_in@nerc.com

bp-2014-01_PRC-005-3(X)_in@nerc.com

bp-2014-01_PRC-005-X(X)_in@nerc.com

bp-2014-01_VAR-002-4_in@nerc.com

bp-2014-01_VAR-002-2b(X_in@nerc.com

bp-PRC005_VAR002_DGR_IP_in@nerc.com

Next Steps

A ballot period for the standards and implementation plans will be conducted **July 18-28, 2014.**

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Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources

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bp-2014-01_PRC-005-2(X)_in@nerc.com

bp-2014-01_PRC-005-3(X)_in@nerc.com

bp-2014-01_PRC-005-X(X)_in@nerc.com

bp-2014-01_VAR-002-4_in@nerc.com

bp-2014-01_VAR-002-2b(X_in@nerc.com

bp-PRC005_VAR002_DGR_IP_in@nerc.com

Next Steps

A ballot period for the standards and implementation plans will be conducted **July 18-28, 2014.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2014-01 Applicability for Dispersed Resources Standards

Ballot Results

Now Available

Ballots for five **Project 2014-01 Dispersed Generation Resources Reliability Standards, (PRC-005-2(X), PRC-005-3(X), PRC-005-X(X), VAR-002-2b(X), and VAR-002-4)** concluded at **8 p.m. Eastern on Tuesday, July 29, 2014**.

The standards achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

	Ballot Results
	Quorum /Approval
PRC-005-2(X)	79.49% / 91.38%
PRC-005-3(X)	80.15% / 92.20%
PRC-005-X(X)	80.00% / 89.51%
VAR-002-2b(X)	80.83% / 90.58%
VAR-002-4	80.36% / 87.09%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact [Wendy Muller](),
Standards Development Administrator, or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2014-01 PRC-005-2(X)
Ballot Period:	7/18/2014 - 7/29/2014
Ballot Type:	Initial
Total # Votes:	314
Total Ballot Pool:	395
Quorum:	**79.49 % The Quorum has been reached**
Weighted Segment Vote:	91.38 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	63	0.955	3	0.045	0	19	20
2 - Segment 2	8	0.4	2	0.2	2	0.2	0	2	2
3 - Segment 3	89	1	54	0.931	4	0.069	0	15	16
4 - Segment 4	29	1	17	0.895	2	0.105	0	3	7
5 - Segment 5	93	1	52	0.929	4	0.071	0	14	23
6 - Segment 6	54	1	35	0.921	3	0.079	0	7	9
7 - Segment 7	3	0.1	1	0.1	0	0	0	0	2
8 - Segment 8	4	0.4	4	0.4	0	0	0	0	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	8	0.6	6	0.6	0	0	0	1	1
Totals	**395**	**6.6**	**235**	**6.031**	**18**	**0.569**	**0**	**61**	**81**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilties)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson		
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	

1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS -

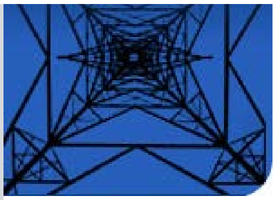
				(ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Kaleb Brimhall)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker		
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	

3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith		
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of FMPA)
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
				COMMENT

4	Modesto Irrigation District	Spencer Tacke	Negative	RECEIVED
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Renewable Power	Marcus Ellis		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden	Negative	COMMENT RECEIVED
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik		

5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs

				Utilties)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	



10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-01 PRC-005-3(X)
Ballot Period:	7/18/2014 - 7/29/2014
Ballot Type:	Initial
Total # Votes:	315
Total Ballot Pool:	393
Quorum:	**80.15 % The Quorum has been reached**
Weighted Segment Vote:	92.20 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	63	0.94	4	0.06	0	19	19
2 - Segment 2	8	0.4	2	0.2	2	0.2	0	2	2
3 - Segment 3	88	1	55	0.948	3	0.052	0	15	15
4 - Segment 4	29	1	18	0.947	1	0.053	0	3	7
5 - Segment 5	92	1	52	0.929	4	0.071	0	14	22
6 - Segment 6	54	1	35	0.921	3	0.079	0	7	9
7 - Segment 7	3	0.1	1	0.1	0	0	0	0	2
8 - Segment 8	4	0.4	4	0.4	0	0	0	0	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	8	0.6	6	0.6	0	0	0	1	1
Totals	**393**	**6.6**	**237**	**6.085**	**17**	**0.515**	**0**	**61**	**78**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilties)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson		
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	

1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Kaleb Brimhall)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker		
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		

3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	

4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden	Negative	COMMENT RECEIVED
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	

5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilties)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Affirmative	

6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Account Log-In/Register

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Ballot Results	
Ballot Name:	Project 2014-01 PRC-005-X(X)
Ballot Period:	7/18/2014 - 7/29/2014
Ballot Type:	Initial
Total # Votes:	316
Total Ballot Pool:	395
Quorum:	**80.00 % The Quorum has been reached**
Weighted Segment Vote:	89.51 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	62	0.925	5	0.075	0	19	19
2 - Segment 2	8	0.5	2	0.2	3	0.3	0	1	2
3 - Segment 3	89	1	54	0.931	4	0.069	0	15	16
4 - Segment 4	29	1	16	0.941	1	0.059	0	5	7
5 - Segment 5	93	1	51	0.895	6	0.105	0	14	22
6 - Segment 6	54	1	34	0.895	4	0.105	0	7	9
7 - Segment 7	3	0.1	1	0.1	0	0	0	0	2
8 - Segment 8	4	0.4	4	0.4	0	0	0	0	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	8	0.7	7	0.7	0	0	0	0	1
Totals	**395**	**6.8**	**232**	**6.087**	**23**	**0.713**	**0**	**61**	**79**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilties)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson		
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	

1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Abstain	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(IRC SRC)
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Kaleb Brimhall)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker		
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	

3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrys Energy Group, Inc.	Christopher Plante		

4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden	Negative	COMMENT RECEIVED
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Southwest Power Pool)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		

6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilties)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	

8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-01 VAR-002-2b(X)
Ballot Period:	7/18/2014 - 7/29/2014
Ballot Type:	Initial
Total # Votes:	312
Total Ballot Pool:	386
Quorum:	**80.83 % The Quorum has been reached**
Weighted Segment Vote:	90.58 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	103	1	60	0.938	4	0.063	0	21	18
2 - Segment 2	8	0.4	2	0.2	2	0.2	0	2	2
3 - Segment 3	85	1	54	0.931	4	0.069	0	15	12
4 - Segment 4	27	1	18	0.947	1	0.053	0	2	6
5 - Segment 5	92	1	53	0.93	4	0.07	0	13	22
6 - Segment 6	54	1	36	0.923	3	0.077	0	5	10
7 - Segment 7	3	0.1	1	0.1	0	0	0	0	2
8 - Segment 8	4	0.4	3	0.3	1	0.1	0	0	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	8	0.7	7	0.7	0	0	0	0	1
Totals	**386**	**6.7**	**235**	**6.069**	**19**	**0.632**	**0**	**58**	**74**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilties)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson		
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	

1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - ISO/RTO SRC
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
				SUPPORTS

2	MISO	Marie Knox	Negative	THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Kaleb Brimhall, Colorado Springs Utilities)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	

3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	

4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren's comments)
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorad Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	

5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilties)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-01 VAR-002-4
Ballot Period:	7/18/2014 - 7/29/2014
Ballot Type:	Initial
Total # Votes:	311
Total Ballot Pool:	387
Quorum:	**80.36 % The Quorum has been reached**
Weighted Segment Vote:	87.09 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	103	1	55	0.846	10	0.154	0	20	18
2 - Segment 2	8	0.4	2	0.2	2	0.2	0	2	2
3 - Segment 3	85	1	50	0.847	9	0.153	0	14	12
4 - Segment 4	27	1	18	0.947	1	0.053	0	2	6
5 - Segment 5	93	1	51	0.895	6	0.105	0	12	24
6 - Segment 6	54	1	36	0.9	4	0.1	0	4	10
7 - Segment 7	3	0.1	1	0.1	0	0	0	0	2
8 - Segment 8	4	0.4	3	0.3	1	0.1	0	0	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	8	0.7	7	0.7	0	0	0	0	1
Totals	**387**	**6.7**	**224**	**5.835**	**33**	**0.865**	**0**	**54**	**76**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilties)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson		
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	

1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		

1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - ISO/RTO SRC
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Kaleb Brimhall, Colorado Springs Utilities)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	

3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Aeci)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	

3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Negative	COMMENT RECEIVED
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren's comments)
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	

5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		

5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI comment)
6	Basin Electric Power Cooperative	Stephen Farnsworth	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG) - (Colorado Springs Utilties)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		

6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Individual or group. (36 Responses)
Name (22 Responses)
Organization (22 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
Question 1 (32 Responses)
Question 1 Comments (34 Responses)
Question 2 (32 Responses)
Question 2 Comments (34 Responses)
Question 3 (30 Responses)
Question 3 Comments (34 Responses)
Question 4 (28 Responses)
Question 4 Comments (34 Responses)
Question 5 (27 Responses)
Question 5 Comments (34 Responses)
Question 6 (30 Responses)
Question 6 Comments (34 Responses)

Individual
Heather Bowden
EDP Renewables North America LLC
No
For consistency, it should be considered to have PRC-004 and PRC-005 to be applicable at an aggregate of greater than or equal to 75 MVA of BES facilities.
No
For consistency, it should be considered to have PRC-004 and PRC-005 to be applicable at an aggregate of greater than or equal to 75 MVA of BES facilities.
No
For consistency, it should be considered to have PRC-004 and PRC-005 to be applicable at an aggregate of greater than or equal to 75 MVA of BES facilities.
Yes
Yes
Thank you for your time and efforts.
Individual
Jim Nail`
Independence Power & Light
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Yes
Yes
Yes

No
Individual
Joe Butterfield
Wisconsin Public Service Corporation
No
The PRC-005-2(X) facilities sections (4.2.6 and 4.2.6.1) should be clarified and consistent with section 4.2.5. Suggested clarification: 4.2.6 Protection Systems for the following BES dispersed power producing resources identified through Inclusion I4 of the BES definition; excluding the individual resources: 4.2.6.1 Protection Systems that act to trip a common point of connection at 100 kV or above where those resources aggregate to greater than 75 MVA, either directly or via a lockout relay. OR 4.2.6.1 Protection Systems that act to trip dispersed power producing resources common point of connection at 100 kV or above where those resources aggregate to greater than 75 MVA, either directly or via lockout relay.
No
The PRC-005-3(X) facilities sections (4.2.6 and 4.2.6.1) should be clarified and consistent with section 4.2.5. Suggested clarification: 4.2.6 Protection Systems for the following BES dispersed power producing resources identified through Inclusion I4 of the BES definition; excluding the individual resources: 4.2.6.1 Protection Systems that act to trip a common point of connection at 100 kV or above where those resources aggregate to greater than 75 MVA, either directly or via a lockout relay. OR 4.2.6.1 Protection Systems that act to trip dispersed power producing resources common point of connection at 100 kV or above where those resources aggregate to greater than 75 MVA, either directly or via lockout relay.
No
The PRC-005-X(X) facilities sections (4.2.6 and 4.2.6.1) should be clarified and consistent with section 4.2.5. Suggested clarification: 4.2.6 Protection Systems for the following BES dispersed power producing resources identified through Inclusion I4 of the BES definition; excluding the individual resources: 4.2.6.1 Protection Systems that act to trip a common point of connection at 100 kV or above where those resources aggregate to greater than 75 MVA, either directly or via a lockout relay. OR 4.2.6.1 Protection Systems that act to trip dispersed power producing resources common point of connection at 100 kV or above where those resources aggregate to greater than 75 MVA, either directly or via lockout relay. In addition, there should be further clarification surrounding the inclusion/exclusion of the sudden pressure relay.
Yes
Yes
No
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Yes
Yes
Yes

No
Individual
Terry Volkmann
Volkmann COnsulting, Inc
Yes
Yes
Yes
No
The change is neither consistent with the delineation in PRC-004 / 5 nor inclusive of the dispersed generation issue. My interpretation is that VAR-002 change only address change in reactive capability and does not address automatic voltage control and status at each generator site. VAR-002 should be written explicitly to only applicable at the point of aggregation to 75 MVA with the transmission system.
No
see question 4
No
Individual
John Seelke
Public Service Enterprise Group
No
In 4.2.6.1, “75MVA should be changed to “20MVA.” This would make it comparable to I2 generators. Although the change to 20MVA would have this standard apply to non-BES assets, many standards do likewise. In fact “Protection Systems,” which are the subject of this standard, are non-BES. As written, a reliability gap would be created between I4 generators and I2 generators. The proposed change violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: “Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage.” If alternative language was proposed that required the same 75MVA threshold for I2 generators, PSEG would be fine with that. But the proposed non-comparable treatment of generators is not acceptable.
No
The same comments in Q1 apply.
No
The same comments in Q1 apply.
No
How does one interpret the added “bullet” in R3? The new bullet statement belongs in the Applicability section. Furthermore, the statement creates a reliability gap between I4 generators and I2 generators. It also violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: “Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage.” We suggest the following addition to the bullet to correct both issues (added language is CAPITALIZED): “…. Bulk Electric Definition; HOWEVER, REPORTING CHANGES ARE REQUIRED AT THE POINT THAT INDIVIDUAL INCLUSON I4 BES GENERATORS AGGREGATE TO GREATER THAN 20MVA.”
No
The same comments in Q3 apply, except replace “R3” with “R4.”
No

Individual
Anthony Jablonski
ReliabilityFirst
Yes
ReliabilityFirst submits the following comments for consideration: 1. VAR-002-2b(X) Requirement 3, Part 3.1 - The exclusion for dispersed power producing resources is shown as a bullet point and bullet points are historically described as “OR” statements in NERC Reliability Standards. ReliabilityFirst recommends adding the bulleted language to the end of Requirement 3, Part 3.1 as follows: “A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability. Reporting of status or capability changes is not applicable to the individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.”
Group
MRO NSRF
Joseph DePoorter
No
The proposed wording within the Applicability section of 4.2.5 is very wordy and without the Rational box for 4.2.5, entities will be very confused. The NSRF recommend that 4.2.5 be reworded to read; “Protection Systems for BES generation Facilities (Inclusion I4 assets are contained within section 4.2.6)”. This will allow all BES connected generators to be covered by this Standard and clearly describes what is applicable per Inclusion I4 via 4.2.6.
No
See comments per question 1.
No
See comments per question 1.
No
The NSRF agrees with the proposed Requirements but has issues with the associated Rational for Footnote 5 in R4, Part 4.1, note that Transmission Provider should be Transmission Planner. The auxiliary transformers stated in R4.1 are usually transformers that provide station services to the generator. The first sentence of the Ration is correct. The second sentence is out of line since it is directed to the collector system (34.5kV), this should be deleted. This rewrite will provide simple clarity that the foot note is trying to provide.
No
The bulleted item under R4 is too wordy and recommend the following rewrite to provide clarity; “Reporting of reactive capability changes is not applicable to (delete “the”) individual (delete “for “) dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.
Yes
Please note that NERC has already written a proposed Guidance document on these Standards, including PRC-004. The NSRF, request that the SDT coordinate with NERC so that any Standard and Guidance document complement each other.
Individual
Thomas Foltz
American Electric Power
Yes

Yes
Yes
Was the omission of sudden pressure relays for dispersed generation resources under PRC-005-X Applicability 4.2.6 intentional? In light of the FERC directive associated with SPRs, we are unsure if FERC will accept a version of the standard that does not require testing of SPRs for transformers connected between the point that the resources aggregate to greater than 75 MVA and the point of interconnection.
Yes
Yes
No
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
Yes
Yes
Yes
Yes
No
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
In Quebec, the RTP (Main Transmission System) Elements are applied instead of BES Elements. The Generation Facilities are greater than 50 MVA / 44kV instead of 75 MVA. Also in Quebec, NO Dispersed Generation is connected into the RTP network. To facilitate the compliance, the expression ‘inclusion I4’ should NOT include in the standard.
No
See response in question 1
No
See response in question 1
No
See response in question 1
No
Group
Dominion
Connie Lowe

No
Dominion recommends revising 4.2.5 to read “Protection Systems for the following BES generator Facilities identified through Inclusions I2 and I3 of the BES definition:” as we believe it is more appropriate to cite how these BES generators are included under this section as opposed to indicating how they are not applicable under this section. Currently the standard’s applicability is based first on the NERC Registration Criteria and secondly on facilities identified within the standard (4.2.5 Protection Systems for generator Facilities), regardless of their BES status. This proposed revisions means to change the applicability of the standard first to the NERC Registration Criteria and secondly on facilities identified within the standard (4.2.5 Protection Systems for BES generator Facilities). This BES generator Facilities change in 4.2.5 (i.e. Inclusions I2 and I3) essentially means the Protection System to be considered now is the “generator including the generator terminals through the high-side of the step-up transformer” and no longer considers protection to the point of interconnection.
No
Dominion recommends revising 4.2.5 to read “Protection Systems for the following BES generator Facilities identified through Inclusions I2 and I3 of the BES definition:” as we believe it is more appropriate to cite how these BES generators are included under this section as opposed to indicating how they are not applicable under this section.
No
Dominion recommends revising 4.2.5 to read “Protection Systems for the following BES generator Facilities identified through Inclusions I2 and I3 of the BES definition:” as we believe it is more appropriate to cite how these BES generators are included under this section as opposed to indicating how they are not applicable under this section.
Yes
Rationale for R4, need to change Transmission Provider to ‘Transmission Planner’. Since this standard is being revised, Dominion suggests that NERC request the SDT to re-align the Measures with the Requirements to develop a more risk-based standard as NERC has proposed going forward.
Yes
Rationale for R5, need to change Transmission Provider to ‘Transmission Planner’.
Yes
Dominion, from a philosophical perspective, cannot support a continent–wide standard (VAR-002) that does not grant a waiver (or waivers) where one or more approved regional standard exists. We cite the following as reason supporting this philosophy; PRC-006, Docket # RM11-20 - In Order No. 763 (issued on May 7, 2012), the Commission directed NERC to submit a Compliance Filing regarding several aspects including how it will address the Commission’s directive to establish a schedule by the planning coordinator to comply with PRC-006-1 Requirement R9. In its compliance filing, NERC stated that an entity must be compliant with both the continent wide PRC-006 Standard and the regional standard proposed by SERC in Docket No. RM12-9. Dominion intervened requesting that the Commission modify Requirement R6 to require each UFLS entity in the SERC Region to implement changes to the UFLS scheme within the lesser of 18 months of notification by the planning coordinator, or the schedule established by the planning coordinator. In reply to SERC’s responsive comments, Dominion disagrees that its concerns have been adequately addressed. Dominion states that “it is unjust to hold a registered entity responsible for compliance to any requirement within a reliability standard where such compliance is dependent upon that registered entity having also read, and taken into consideration, all statements issued by FERC, NERC and the Regional Entity. The Commission declined Dominion’s request and instead affirmed the interpretation as set forth in NERC and SERC’s comments. PRC-002-2 – NPCC received approval of its regional standard (PRC-002-NPCC-01) in October 2011. That standard also contained an implementation plan which provides staggered effective dates, i.e., the date on which applicable entities are subject to mandatory compliance, with full compliance required within four years of regulatory approval. During the comment period, Dominion stated potential for conflict between the approved regional standard and the draft continent-wide standard, and also noted that registered entities in that region are 2 years into the 4 year implementation which creates uncertainty for NPCC applicable entities. The drafting team’s response did not adequately address Dominion’s concerns. Dominion does not agree with the response provided by the SDT relative to comments related to PRC-006, specifically the regional (NPCC and SERC) versions. Both of these approved regional standards apply to

Generator Owner and we therefore agree that the SDT should include the continent wide standard in its review.
Group
Duke energy
Michael Lowman
Yes
Yes
Yes
Yes
Duke Energy suggests the following revision: “Reporting of status or capability changes is not applicable to the individual dispersed power producing resources identified through Inclusion I4 (a) of the Bulk Electric System definition.” We believe the addition of “I4 (a)” helps clarify the applicability for individual dispersed power producing resources.
Yes
Duke Energy suggests the following revision: “Reporting of reactive capability changes is not applicable to the individual dispersed power producing resources identified through Inclusion I4 (a) of the Bulk Electric System definition.” We believe the addition of “I4 (a)” helps clarify the applicability for individual dispersed power producing resources. We would also like to point out an apparent typo in R4 and suggest modifying “individual for dispersed power producing resources” to” individual dispersed power producing resources”. The removal of “for” provides consistency with the language in VAR-002-2b.
Yes
PRC-005 Implementation Plans: We suggest removing “first day following” in all the PRC-005 implementation plans. It appears that as written, there could be a gap between the effective date and retirement date of these standards. VAR-002-2b RSAW : We suggest adding I4 (a) to the R3 Note To Auditor Section of the RSAW for consistency with our comments to Question 4 as follows: “Requirement R3.1 is not applicable to individual dispersed power producing resources identified through Inclusion I4 (a) of the Bulk Electric System definition. Entity assertions regarding applicability of Requirement R3.1 should be supported by evidence such as one-line diagrams, nameplate ratings, manufacturer information, or BES inclusion documentation available at the Regional Entity.” VAR-002-3 RSAW : We suggest adding I4 (a) to the R4 Note To Auditor Section of the RSAW with our comments to Question 5 as follows: “Requirement R4 is not applicable to the individual dispersed power producing resources identified through Inclusion I4 (a) of the Bulk Electric System definition. Entity assertions regarding applicability of Requirement R4 should be supported by evidence such as one-line diagrams, nameplate ratings, manufacturer information, commissioning tests, etc.”
Individual
Timothy Brown
Idaho Power
No
Inclusion I4 of the BES definition specifically includes each generating resource. It is inconsistent to not include them for testing the protection systems under PRC-005. As written, there would be portions of the Bulk Electric System that would not be required to have the protection systems tested. A GO with a plant of small units aggregating above 75 MVA would be required to test the protection systems on all their units. How is this equitable? I understand that you have addressed this issue in the Consideration of Comments for the White Paper (Pg 9 & 10), however I disagree with your conclusion. If they individual resources are insignificant to test, they why are they considered part of the BES?
No
See discussion in #1.

No
See discussion in #1.
Yes
Yes
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
Yes
Yes
Yes
Yes
1)Texas RE agrees with the change to applicability but points out that there may be an error in the language of R5 of VAR-002-4. Requirement 4 and 5 have the exact same requirement language: “Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability.” Requirement 5 goes on to add: “For generator step-up transformers and auxiliary transformers5 with primary voltages equal to or greater than the generator terminal voltage: 5.1.1. Tap settings. 5.1.2. Available fixed tap ranges. 5.1.3. Impedance data. The requirements in VAR-002-2b (R4) and VAR-002-3 (R5) that include the tap settings, ranges and impedance data language have the following requirement language: “The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.” Texas RE requests the SDT review the language to assure the correct requirement language is included in Requirement R5 of VAR-002-4. 2)It appears that R7 of VAR-002-4 should actually be the Measure for R6, not a Requirement. 3)It appears that VAR-002-2b(X) Requirement R3.1 and VAR-002-4 Requirement R4 map to each other but the exclusion language is slightly different. VAR-002-4, R4 has the word “for” between “individual” and “dispersed power” whereas VAR-002-2b(X) does not. The addition of the word makes the requirement confusing. It may just be a typo but Texas RE wanted to bring this to the attention of the SDT. VAR-002 -2b(X) Requirement R3.1 language: Reporting of status or capability changes is not applicable to the individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. VAR-002-4 Requirement R4 language: Reporting of reactive capability changes is not applicable to the individual for dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.
No
Group
DTE Electric
Kathleen Black
Yes
Yes

Yes
Yes
Yes
No
Group
FirstEnergy
Cindy Stewart
No
FirstEnergy abstains as we are not directly impacted by this project. Please see our response to Question #6.
No
FirstEnergy abstains as we are not directly impacted by this project. Please see our response to Question #6.
No
FirstEnergy abstains as we are not directly impacted by this project. Please see our response to Question #6.
No
FirstEnergy abstains as we are not directly impacted by this project. Please see our response to Question #6.
No
FirstEnergy abstains as we are not directly impacted by this project. Please see our response to Question #6.
Yes
FirstEnergy abstains as we are not directly impacted by this project. We question the efficiency of modifying several NERC Reliability Standards in lieu of potentially adjusting the NERC BES definition which may more effectively address the concerns. Additionally there are other revisions to the NERC BES definition needed in regard to generation assets. As written, there is inequality in the NERC BES definition for traditional generation resources versus dispersed generation. A single traditional unit of 25 MVA must meet all NERC Reliability Standards that apply to Generator Owners yet for the dispersed generation they are only subject to the extent that they total 75 MVA or more. When there are standards before FERC pending regulatory approval, all subsequent revisions should be based on the latest NERC Board approved version. It is our opinion that the approach taken to modify and post for ballot several versions of the same standard is inefficient, overly complicated and unnecessarily causes industry confusion. We suggest that the NERC Standards Committee reassess the need to make this a standalone project and work the intended revisions into current ongoing projects.
Individual
David Jendras
Ameren
Yes
Ameren adopts the SERC PCS comments by reference
Yes
Ameren adopts the SERC PCS comments by reference
Yes
Ameren adopts the SERC PCS comments by reference
Yes

No
(1) Regarding proposed standard VAR-002-4, we believe that some language is missing for requirement R5.1. Shouldn’t the requirement state that the Generator Operator needs to provide the information on Tap Settings, Available fixed tap ranges, and Impedance data to the Transmission Operator? (2) We believe that VAR-002-4 should include a 30 day time period to complete R5, as alluded to in M5.
No
Group
SERC Protection and Controls Subcommittee
David Greene
Yes
Please word the standard to clearly identify that PRC-005 becomes applicable on facilities where the aggregate generation sums to > 75MVA and it connects at >100kV. Please refer to Figures in the BES Definition Reference document to clearly identify the applicable facilities where the aggregate generation sums to > 75MVA and it connects at >100kV. For example in the BES Definition Reference Document Figures I4-1 through I4-4, is the protection system on the blue bus in the purple circle included given that the green feeders are not BES? Or, is just the transformer protection applicable since it is clearly all blue (BES) in the diagram? As another example in the BES Definition Reference Document Figure I4-1, can each of the 4 green strings of distributed generation be owned by the same or different companies, located at one or separate locations and the blue collector bus actually be a sub transmission line (or distribution line)?
Yes
See comments with Question 1.
Yes
See comments with Question 1.
no comment
no comment
No
The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Group
Florida Municipal Power Agency
Carol Chinn
Yes
Yes
Yes
In the rationale for Footnote 5 in Requirement R4, Part 4.1 the references to Transmission Provider should be Transmission Planner. The reference to “Transmission” should be Transmission Planner.
In the added bullet to R4, the word “for” should be deleted. In the rationale for Footnote 5 in Requirement R5, Part 5.1 the references to Transmission Provider should be deleted. The reference to “Transmission” should be deleted. Although not in the scope of this particular SDT, the reference to Transmission Planner in M5 should be deleted since notification is not required by R5.
No
Group
SPP Standards Review Group

Robert Rhodes
No
Rewrite the 1st line under Description of Current Draft to read: 'This version of PRC-005 contains revisions to the applicability of the Standard intended to…' This eliminates the redline typo. In order to minimize confusion regarding the use of the term 'Facilities' versus 'facilities' in the Applicability Section, we recommend changing the heading of 4.2 to 'Applicable facilities'. Insert a space between the 'apply' and the 'only' in the 6th line of the Rationale Box for 4.2.6. Also expand the box down to capture all of the last line. We also suggest that the formatting in 4.2.6 parallel the formatting, or construction, of 4.2.5 in that specifics are listed in 4.2.5 and they are absent in 4.2.6. Or the drafting team could go in the other direction and modify 4.2.5 to match 4.2.6. The redline version contained several Rationale Boxes which are missing from the clean version. Were the boxes holdovers from previous versions making the clean version the correct copy or were they supposed to be included in the clean version?
No
In order to minimize confusion regarding the use of the term 'Facilities' versus 'facilities' in the Applicability Section, we recommend changing the heading of 4.2 to 'Applicable facilities'. We also suggest that the formatting in 4.2.6 parallel the formatting, or construction, of 4.2.5 in that specifics are listed in 4.2.5 and they are absent in 4.2.6. Or the drafting team could go in the other direction and modify 4.2.5 to match 4.2.6.
No
Shouldn't the reference to PRC-005-3 in the 2nd line under the Description of Current Draft be to PRC-005-4? The redline version shows a Rationale Box with the Introduction Section. This box, even though it contains redline changes, is not included in the clean version. Were the redline changes holdovers from a previous version and should not have been shown in this redline or were they supposed to be included in the clean version? In order to minimize confusion regarding the use of the term 'Facilities' versus 'facilities' in the Applicability Section, we recommend changing the heading of 4.2 to 'Applicable facilities'. The page header includes the PRC-005-4(X) label while within the standard itself it is shown as PRC-005-X. Which is correct? We would also suggest that the formatting in 4.2.6 parallel the formatting, or construction, of 4.2.5 in that specifics are listed in 4.2.5 and they are absent in 4.2.6. Or the drafting team could go in the other direction and modify 4.2.5 to match 4.2.6. The Rationale Boxes for 4.2.5 and 4.2.6 cover-up text. The boxes need to be moved such that they do not cover-up any text.
No
References to R4 and R5 in the Description of Current Draft Section should be to R3 and R4. Also delete the BES in front of Bulk Electric Systems in the line in which the references are made. The proposed change to Requirement R3, Part 3.1 is okay as long as the number of individual units in an aggregated site is not detrimental to the overall operation of the entire site. In that case, the site status, for the entire aggregated facility, should be reported. If this is the intent of Part 3.2, it needs additional clarification to make it stand out. The Rationale Box for Footnote 5 references the Transmission Provider and in one instance only references Transmission. We believe these references should be to the Transmission Planner as indicated in Requirement R4.
No
Since VAR-002-4 only contains minor technical revisions dealing with the applicability specifically for Requirements R4 and R5, is it feasible to believe that VAR-002-4 will be approved before VAR-002-3? The special provisions for 'the later of' aren't needed. Simply go with the normal Effective Date language. Additionally, the way this section is currently worded in those jurisdictions requiring governmental approval, the standard becomes effective immediately upon governmental approval. Yet, if governmental approval is not required, the standard would become effective the first day of the first calendar quarter following NERC Board approval. The concept of 'the first day of the first calendar quarter following approval' needs to be added to the governmental approval clause. The same argument applies to the proposed change for Requirement R4 as we put forth in response to the proposed change to Requirement R3, Part 3.1 in VAR-002-2b(X) in Question 4. The proposal is okay provided that only lost capability of a few individual units does not detract from the overall capability of the entire aggregated site. If the capability of the entire site is degraded the notification should be made. Also, insert the term 'generator' between 'individual' and 'for' in the bullet under Requirement R4. Requirement R5 is a duplicate of Requirement R4 and needs to be replaced with

the correct wording from VAR-002-2b(X), Requirement R4. The clean version is missing the Rationale Box for Footnote 5.
Yes
The various Implementation Plans for each version of PRC-005 are cross referenced in the Implementation Plans for PRC-005-2(X), PRC-005-3(X) and PRC-005-X(X) in this project. We suggest a change in language to an item in the Background Section of each of those referenced Implementation Plans. We propose the following: ‘2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program. Those entities which now fall under the requirements of the standard due to BES definition changes would have twenty-four months from the applicable effective date to demonstrate compliance.’ This would eliminate the potential for a repeat of the fiasco of a few years back associated with implementation of PRC-005-1 in which evidence of compliance was required prior to the effective date of the standard. There is inconsistency among the proposed standards on the term dispersed power producing facilities. In some instances power producing is hyphenated, in others it is not. In some instances facilities is capitalized, in others it is not. The SDT needs to determine which is correct and stick to it. There is inconsistency among the proposed standards on the use of the terms 75 MVA and 100 kV. In some instances they are shown with the space and in others they are shown without the space as 75MVA and 100kV. The SDT, again, needs to determine which is correct and stick to it.
Individual
John Pearson
ISO New England
No
Under the standard, a conventional generating resource has to have a documented protection maintenance program which it must follow to ensure reliability. On the other hand, under the proposed revisions to the standard, a similarly-sized, dispersed power producing resource would not be required to do the same. If the standard is not applied to the dispersed generation resource, then there is no required protection maintenance, which can (and does in practice) result in more frequent trips, and degraded reliability. Loss of the dispersed generation resource (as distinct from individual units) would have the same impact as loss of a single, similarly sized conventional generating resource. Thus, a maintenance program that applies beyond the common point of connection should be required. The maintenance program should definitely be tailored to the type of dispersed generation power producing resource as determined by the GO/GOP, but having no requirement in place does not ensure reliable operations.
No
See response for Question 1
No
See response for Question 1
Yes
In PRC-005-2(X), under A.2, the number “2” should not have been deleted and the letter “X” should be in parenthesis as it is shown in the header. In PRC-005-2(X), and VAR-002-2b(X), under D. Compliance 1.1 – It is not necessary to repeat the definition of Compliance Enforcement Authority. A reference to the NERC Rules of Procedure is sufficient. The benefit is that, if the definition ever changes there, it will not have to be changed here. Therefore, 1.1 under Compliance should simply say: “Compliance Enforcement Authority” has the meaning ascribed to it in the NERC Rules of Procedure.
Individual
John Robertson
First Wind
Yes

Applicability is adequate for reliability.
Yes
Applicability is adequate for reliability.
Yes
Applicability is adequate for reliability.
Yes
Yes
No
Individual
George Brown
Acciona Energy North America Corporation
Yes
Yes
Yes
Yes
No
I agree with the intent of the SDT, however, the balloted version VAR-002-4 is incorrect. VAR-002-4 R4: added applicability clause is incorrect and misworded VAR-002-4 R5: Requirement is incorrect and not original requirement from version 3 of this standard
No
Individual
Israel Beasley
Georgia Transmission Corporation
Yes
Yes
The only comments I would suggest are fixing the wording in the Automatic Reclosing section 4.2.7.2 of PRC-005-3/PRC-005-X to refer to section 4.2.7.1 instead of 4.2.6.1. It appears this change was simply overlooked.
Yes
The only comments I would suggest are fixing the wording in the Automatic Reclosing section 4.2.7.2 of PRC-005-3/PRC-005-X to refer to section 4.2.7.1 instead of 4.2.6.1. It appears this change was simply overlooked.
Yes
The only comments I would suggest are fixing the wording in the Automatic Reclosing section 4.2.7.2 of PRC-005-3/PRC-005-X to refer to section 4.2.7.1 instead of 4.2.6.1. It appears this change was simply overlooked.
Group
IRC Standards Review Committee
Greg Campoli

Yes
Yes
Yes
The proposed change to Requirement R3, Part 3.1 is okay as long as the net change to number of the individual units in an aggregated site is not detrimental to affect the overall operation of the entire site or the proper management and control of reactive resources of the site. In that case, the site status, for the entire aggregated facility, should be reported. If this is the intent of Part 3.2 is intended to cover the latter situation (where the impact of changes to individual disperse generating sources is reported at the aggregate level), then Part 3.2 needs , it needs additional to be expanded to clarify it. clarification to make it stand out. Otherwise, the impact of changes to individual units will not be identified and reported for control to meet the objective of control and management of reactive resources. The Rationale Box for Footnote 5 references the Transmission Provider and in one instance only references Transmission. We believe these references should be to the Transmission Planner as indicated in Requirement R4.
Yes
There are multiple postings of the PRC-005 currently underway, each effort addressing different changes. Although we support and understand the need to adhere to the standards development process for standards projects, each one will have individual postings and ballots. This makes it cumbersome to reference and review layers of changes that may impact the other postings and can lead to confusion and unanticipated voting outcomes. The drafting teams need to explain how each proposed change to PRC-005 is not relevant or impactive on the other.
Individual
Joshua Andersen
Salt River Project
Yes
Yes
No
Sudden pressure relays are not “necessary”, in fact, older transformers will likely not have them. What is necessary for “reliable operation” as defined in the statute are the differential relays, overcurrent relays, etc., that are there to clear a major phase to phase or phase to ground fault that if left uncleared can cause instability. A sudden pressure relay is there primarily for equipment health monitoring, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault.
Yes
Yes
No
Group
ACES Standards Collaborators
Jason Marshall
Yes
We agree with the changes.

Yes
We agree with the changes.
Yes
We agree with the changes.
Yes
(1) We agree with the proposed changes. However, we believe additional changes are needed to the standard. (2) Requirement R1 needs to be modified as well. Because each individual generating unit of a dispersed generation site that exceeds the 75 MVA threshold is included as part of the BES, R1 would apply and would require each of these units to be operated with AVR in voltage regulating mode. These units usually do not have an AVR and are not capable of controlling voltage. Rather, they rely on other voltage regulating equipment such as SVC or capacitor banks to control voltage at the interconnecting point. Thus, we request that R1 is modified so that is not applicable to the individual units of the dispersed power producing resources. (3) Similar to R1, R2 should also be modified to reflect that these dispersed generation resources often do not have AVRs and must rely on other voltage regulating equipment to control voltage at the interconnecting point. Thus, we request that R2 is modified so that is not applicable to the individual units of the dispersed power producing resources.
Yes
(1) We agree with the proposed changes. However, we believe additional changes are needed to the standard. (2) Requirement R1 needs to be modified as well. Because each individual generating unit of a dispersed generation site that exceeds the 75 MVA threshold is included as part of the BES, R1 would apply and would require each of these units to be operated with AVR in voltage regulating mode. These units usually do not have an AVR and are not capable of controlling voltage. Rather, they rely on other voltage regulating equipment such as SVC or capacitor banks to control voltage at the interconnecting point. Thus, we request that R1 is modified so that is not applicable to the individual units of the dispersed power producing resources. (3) Similar to R1, R2 should also be modified to reflect that these dispersed generation resources often do not have AVRs and must rely on other voltage regulating equipment to control voltage at the interconnecting point. Thus, we request that R2 is modified so that is not applicable to the individual units of the dispersed power producing resources.
No
Individual
Steven Lancaster
BES
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Southern Company Generation, Southern Company Generation and Energy Marketing
Pamela Hunter
Yes
The drafting team has identified the appropriate aggregation point for dispersed power producing resources.
Yes
The drafting team has identified the appropriate aggregation point for dispersed power producing resources.
The drafting team has identified the appropriate aggregation point for dispersed power producing resources.
Yes
Yes
No

Individual
Spencer
Tacke
No
For all three PRC-005 proposed modifications, I think we still need to replace the 75 MVA generator size requirement with the 20 MVA size requirement, for the following reasons: WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed. Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2018. Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
No
For all three PRC-005 proposed modifications, I think we still need to replace the 75 MVA generator size requirement with the 20 MVA size requirement, for the following reasons: WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed. Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2018. Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
No
For all three PRC-005 proposed modifications, I think we still need to replace the 75 MVA generator size requirement with the 20 MVA size requirement, for the following reasons: WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed. Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2018. Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
No
For both VAR-002 proposed modifications, I don’t think we should state non-applicability of the Standard for dispersed generation resources indentified through Inclusion I4 of the BES definition, for the following reasons: WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the

years to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed. Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2018. Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
No
For both VAR-002 proposed modifications, I don't think we should state non-applicability of the Standard for dispersed generation resources indentified through Inclusion I4 of the BES definition, for the following reasons: WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed. Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2018. Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
No
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
Yes
4.2.5 is written strangely. "Protection Systems for the following BES generator Facilities not identified through Inclusion I4 of the BES definition" reads better.
Yes
4.2.5 is written strangely. "Protection Systems for the following BES generator Facilities not identified through Inclusion I4 of the BES definition" reads better.
Yes
4.2.5 is written strangely. "Protection Systems for the following BES generator Facilities not identified through Inclusion I4 of the BES definition" reads better.
Yes
Yes
"R7" should be "M6". The effective date is confusing as written and makes it seem as if the standard would be effective immediately. Was that the SDT's intentions? Since VAR-002-3 is still waiting on FERC approval and is not effective yet the industry should have some time to prepare for VAR-002-4.
No
Individual
Michael Moltane

ITC
Yes
Regarding VAR-002, ITC makes the following comments: The Standard should define dispersed power producing resource. While in a practical sense this is a facility comprised of wind turbines or PV inverters, offering exclusions from Requirements based on an undefined criteria is not a good practice. R4 – ITC recommends removal of the sub-bullet under R4 excluding the generators identified through Inclusion I4. The exclusion using BES I4 is confusing and may conflict with existing standard VAR-001-4. A non-BES unit or several non-BES units combined together could have an impact on the BES and thus removing the generators from VAR-002-4 R4 solely based on Inclusion I4 may be detrimental to reliability. Per VAR-001-4 R4, the TOP is required to specify criteria that will exempt generators from following a voltage or reactive power schedule and associated notification requirements. Therefore, ITC recommends that VAR-002-3 R4 should be reworded as “Unless exempted by the Transmission Operator, each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement 3”. The TOP can determine what notifications are necessary and be more specific depending on the needs of the system or individual facility. For example, a TOP exemption criteria may contain: “Dispersed power producing facilities are exempt from reactive capability change notifications less than 10% of the total aggregate lagging reactive capability as measured at the POI at nominal voltage”. TOPs typically will not want to receive individual turbine outage notifications; however, there may be instances where a dispersed power producing resource could lose an individual unit that may affect reliable operations (i.e. large individual units). In addition, the sub-bullet language in VAR-002-4 may be interpreted such that generators not in BES are exempt from reactive capability notifications and, in turn, exempt from following schedules which may be in conflict with VAR-001-4 and potentially impact the reliability of the BES. VAR-001-4 requires the TOP to determine the exemption criteria for generators and ITC recommends that VAR-002-4 be consistent with this practice as the TOP may require non-BES generators to follow a voltage or reactive power schedule based on the collective impact to the BES. R5 – The language in VAR-002-4 R5 is a repeat of the VAR-002-4 R4 language and does not correspond to sub-requirement R5.1 . Replace with appropriate R5 language from VAR-002-3. Similar to R4, the exclusion shouldn’t be based on BES I4. ITC recommends the footnote is reworded to: “For dispersed power producing resources, this requirement applies only to those transformers that have at least one winding at the same or higher voltage as the lowest voltage Point of Interconnection location(s).”
Group
Bonneville Power Administration
Andrea Jessup
Yes
This approach relies on maintenance practices of individual generators and collector systems before reaching the aggregation points as provided by the generator owner. This is in their best interest and in the best interest of the industry.
Yes
This approach relies on maintenance practices of individual generators and collector systems before reaching the aggregation points as provided by the generator owner. This is in their best interest and in the best interest of the industry.
Yes
This approach relies on maintenance practices of individual generators and collector systems before reaching the aggregation points as provided by the generator owner. This is in their best interest and in the best interest of the industry.
Yes

Yes
No
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
Please clarify whether Protection System Maintenance only applies to the aggregate transformers, but not the individual wind generators and its respective step-up transformers.
Yes
Yes
Yes
: Please clarify that Protection System Misoperations of the individual wind generators affects only themselves, but will not cause an aggregate effect with other wind turbines. For example, this standard only applies to aggregate substation transformers. There is a concern that still lies on meeting requirements R1 and R2, operating in voltage control mode. Some existing wind generators operate in a power factor control mode, not voltage control mode, and is not capable of operating in either voltage or power factor control mode.
Yes
Comment 1: These revisions are logical and simply needed to clarify applicability. In fact, not approving these revisions may be detrimental to reliability or not useful to the support of the reliable operation of the BES. Moreover, preparing for implementation under the chance the revisions are not approved is diverting time and resources that could otherwise be devoted to efforts that do contribute to the reliable operation of the BES. Comment 2: Please proceed expeditiously with these revisions and convey such urgency to the approving entities. Although the goal of this effort is to ensure these revisions are approved prior to the June 2016 effective date for newly identified elements under the BES definition, affected entities have no alternative but to expend resources and devote time to plan, prepare and begin compliance related activities well before June 2016.

Additional Comments:

AECI
Phil Hart

1. Do you agree with the revisions made in proposed PRC-005-2(X) to clarify applicability of PRC-005-2 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes: X

   Comments: Suggest removing "for generators" in 4.2.5, as this is redundant. Also suggest removing "the following" in 4.2.5, as the following is not a list of generators, but a list of Protection Systems. Suggested wording changes:

"The following Protection Systems for BES generator Facilities not identified through Inclusion I4 of the BES definition:”

2. Do you agree with the revisions made in proposed PRC-005-3(X) to clarify applicability of PRC-005-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes: X

   Comments: The same comments provided to question 1 also apply to question 2.

3. Do you agree with the revisions made in proposed PRC-005-X(X) to clarify applicability of PRC-005-X (the version of PRC-005 containing revisions to address Sudden Pressure relays, being developed in Project 2007-17.1) to dispersed power-producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes: X

   Comments: The same comments provided to question 1 also apply to question 3.

4. Do you agree with the revisions made in proposed VAR-002-2b(X) to clarify applicability of VAR-002-2b to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes: X

5. Do you agree with the revisions made in proposed VAR-002-4 to clarify applicability of VAR-002-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   Comments: The bullet describing the DGR exclusion for R4 lacks identification of what “individual” is being excluded, and as written could create confusion. The rationale states the intent is to exclude the individual resources from R4. Suggested revised bullet: “Reporting of reactive capability changes is not applicable to the individual resource for dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System Definition.” The bullet used in VAR-002-2b(X) could also be used here, however it lacks specificity.

6. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

   Yes:

   No: X

Consideration of Comments

Project 2014-01 Applicability for Dispersed Generation Resources Standards

The Dispersed Generation Resources (DGR)[1] Standards Drafting Team (SDT) thanks all commenters who submitted comments on the standards. These standards were posted for a 45-day public comment period from June 12, 2014 to July 28, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 36 sets of comments, including comments from approximately 127 different people from approximately 89 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

This document contains the SDT's response to all industry comments received during this comment period. The SDT encourages commenters to review its responses to ensure all concerns have been addressed. The SDT notes that a significant majority of commenters agree with the SDT's recommendations on these standards, but that several commenters expressed specific concerns. Some comments supporting the SDT's recommendations are discussed below but in most cases are not specifically addressed in this response. Also, several comments in response to specific questions are duplicated in other questions, and several commenters raise substantively the same concerns as others. Therefore, the SDT's consideration of all comments is addressed in this section in summary form, with duplicate comments treated as a single issue.

1. Summary Consideration

Industry overwhelming agrees with the SDT's recommendations to make applicability changes or provide guidance to account for the unique characteristics of DGRs in the NERC PRC-005 and VAR-002 standards as evidenced by the initial ballot results. However, there are some disagreements among stakeholders and typographical errors contained in and illuminated by industry comments. The SDT has carefully reviewed and considered each stakeholder comment and has revised its recommendations where suggested changes are consistent with SDT intent and industry consensus. The SDT's consideration of all comments follows.

2. General Comments

Industry identified a number of typographical and formatting errors in each of the posted high-priority standards PRC-005-2(X), PRC-005-3(X), PRC-005-X(X), VAR-002-2b(X), and VAR-002-4. The SDT also identified additional typographical and formatting errors during its most recent review. The SDT has

[1] The terms "dispursed generation resources" and "dispersed power producing resources" are used interchangeably.

corrected each identified typographical and formatting error as reflected in the posted redlined standards.

Some commenters object to including standard language in bullet format. At least one commenter believes that bullet points are historically described as "OR" statements in NERC Reliability Standards. The SDT is unaware of any drafting requirement that compels it to equate bullet points to "or" statements, and its use of the bullet format is consistent with guidance from NERC staff. In the absence of industry consensus or guidance from NERC staff that supports eliminating the bullet format, the SDT is respectfully declines to adopt that suggestion.

At least one commenter notes that in Quebec, the RTP (Main Transmission System) Elements are applied instead of Bulk Electric System (BES) Elements, and that the Generation Facilities are greater than 50 MVA / 44kV instead of 75 MVA. The commenter also notes that in Quebec, no DGRs are connected into the RTP network. The commenter believes that to facilitate compliance, the expression "inclusion I4" should not be included in the standard.

The SDT recognizes that in certain regions there may be additional regional standards and requirements that result in different criteria and thresholds in determining the requirements for Generation Facilities, including those facilities with DGRs. While the SDT intends to provide recommendations on these regional specific standards, making modifications to these standards and their requirements is outside the scope of this project. With respect to the application of the standard under various Canadian provincial and federal regulatory frameworks, the SDT recognizes that certain Canadian provinces have a process to adopt or modify NERC standards for use and enforcement in their specific provinces, and all have discretion to approve and enforce standards according to the needs within their jurisdictions. Therefore, the SDT respectfully declines to adopt this suggestion as inconsistent with its charge, which is specifically to make changes to standards to account for the explicit inclusion of dispersed generation resources under Inclusion I4 of the definition of BES.

3. Recommended Applicability Changes to PRC-005

Several commenters made comments that apply to all DGR versions of the posted PRC-005 standard, which the SDT addresses in this section. Although the SDT addresses industry comments specific to particular versions in the following sections, it considered each comment in the context of all versions of that particular standard to the extent applicable.

At least one commenter asks that the SDT explicitly state in the standard that PRC-005 becomes applicable on facilities where the aggregate generation sums to greater than 75 MVA and it connects at greater than 100 kV, and reference the BES Definition Reference document to clearly identify the applicable facilities where the aggregate generation sums to greater than 75 MVA and it connects at greater than 100 kV.

The BES Definition reference document is intended for use by entities in conjunction with the various reliability standards and their requirements in determining the applicability to their particular facilities. The proposed wording provided by the commenter is included within the BES Definition, which should be used by entities in determining applicability of PRC-005 to their facilities. The Protection Systems applied on the blue busses in figures I4-1 thru I4-4 of the BES Definition Reference Document are intended to be included in the applicable Facilities of the proposed revisions to PRC-005. For inclusion I4 facilities, the owner of the aggregating Facilities that are within scope of the proposed revisions to PRC-005 are responsible for maintaining per the standards requirements, irrespective of whether one or more entities own the various facilities connected. A sub transmission line used in the aggregation of dispersed generation would be within scope of the proposed revision to PRC-005 if the aggregate nameplate generation connected is greater than 75 MVA and the sub-transmission is designed primarily for delivering this generation capacity to a common point of connection at a voltage of 100 kV or above. The SDT respectfully declines to adopt the commenter's recommendations.

At least one commenter suggests that for consistency PRC-004 and PRC-005 should be applicable at an aggregate of greater than or equal to 75 MVA of BES facilities. The SDT recognizes the need to address protection system Misoperations at levels below the aggregate 75 MVA in some instances and has delineated these instances in PRC-004. The SDT believes the proposed "differences" in applicability for PRC-004 and PRC-005 are warranted and that the SDT has provided sufficient technical justification for this approach. Moreover, industry consensus clearly supports the SDT's recommendations on PRC-005. Therefore, the SDT respectfully declines to adopt this suggestion.

At least one commenter advocates replacing the 75 MVA generator size requirement with a 20 MVA size requirement citing a number of factors specific to the WECC region. In order to provide consistent requirements for all generation, the SDT believes it is necessary to assess applicability on individual units greater than 20 MVA and aggregate generation greater than 75 MVA, which are thresholds that have been explicitly recognized and approved by FERC as an appropriate threshold for these types of facilities consistent with the revised BES definition.[2] The SDT therefore does not believe it would be appropriate or technically justifiable to use different aggregation thresholds. The SDT notes that regional requirements may be more stringent than the national standards upheld through NERC and that all entities will need to abide by the applicable region's requirements. Moreover, this position is supported by clear industry consensus. For these reasons, the SDT respectfully declines to adopt this minority position.

At least one commenter believes Inclusion I4 of the BES definition specifically includes each generating resource, and that it is inconsistent to not include them for testing the protection systems under PRC-005. As written, according to the commenter, there would be portions of the BES that would not be

[2] *See* FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000.

required to have the protection systems tested. The commenter believes that a GO with a plant of small units aggregating above 75 MVA would be required to test the protection systems on all their units.

The SDT's scope was to review the applicability of a number of NERC standards as they apply to DGRs and determine if the standard requirements were appropriate. The SDT asserts that relay maintenance on individual units would not provide a significant reliability benefit to the BES and therefore should remain at the discretion of the entity as opposed to a NERC-enforced requirement. Industry consensus supports the SDT's position on this standard. Moreover, it is not within the scope of this project to evaluate the applicability of these standards to non-dispersed power producing resources, including the example of the GO with a plant of small units aggregating above 7 5MVA stated by the commenter. For these reasons, the SDT respectfully declines to adopt the commenter's position.

At least one commenter believes that under the standard, a conventional generating resource has to have a documented protection maintenance program which it must follow to ensure reliability, while under the proposed revisions to the standard, a similarly-sized, DGR would not be required to do the same. According to the commenter, if the standard is not applied to the DGR, then there is no required protection maintenance, which can result in more frequent trips and degraded reliability. The commenter believes that loss of the DGRs as distinct from individual units would have the same impact as loss of a single, similarly sized conventional generating resource, and thus a maintenance program that applies beyond the common point of connection should be required. The commenter believes that the maintenance program should be tailored to the type of DGR as determined by the GO/GOP, but having no requirement in place does not ensure reliable operations.

The SDT believes that the proposed language does require a DGR to have a protection system maintenance plan for the Facilities from the point where those resources aggregate to 75 MVA through to a common point of interconnection at or above 100 kV. In light of clear industry consensus supporting the SDT's recommendations, the SDT respectfully declines to make additional revisions to address this minority concern.

A. PRC-005-2(X)

At least one commenter believes that in order to minimize confusion regarding the use of the term "Facilities" versus "facilities" in the Applicability Section, the SDT should change the heading of 4.2 to "Applicable facilities." The commenter also suggests that the formatting in 4.2.6 parallel the formatting of 4.2.5 in that specifics are listed in 4.2.5 and they are absent in 4.2.6, or modify 4.2.5 to match 4.2.6. Other commenters raise similar consistency concerns.

The SDT intends to refer to "Facilities" in the applicability section; this applicability section and the term "Facilities" is used in a number of standards to describe specific equipment that the standards' requirements should be applied to. The scope of this SDT is to address the applicability to DGRs only, and the SDT feels that changing this section to "facilities" would go beyond the scope of this project. The SDT chose not to list the specific Protection Systems in 4.2.6 like they are listed in 4.2.5, as the SDT believed the language in 4.2.6.1 (i.e., ". . . Facilities used in aggregating dispersed. . .") will result in inclusion of the appropriate Protections Systems for DGR facilities. The SDT also believes the current language is adequate and provides for a clear separation between the requirements for inclusion I4 generators and the requirements for all other BES generators. Consistent with clear industry consensus supporting the SDT's direction on this issue, the SDT respectfully declines to adopt the proposed changes.

At least one commenter believes that in 4.2.6.1, "75 MVA should be changed to "20 MVA." The commenter believes this would make it comparable to I2 generators, and that although the change to 20 MVA would have this standard apply to non-BES assets, many standards do likewise. The commenter notes that "Protection Systems," which are the subject of this standard, are non-BES. The commenter believes that as written, a reliability gap would be created between I4 generators and I2 generators. According to the commenter, the proposed change violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: "Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage."

In order to provide consistent requirements for all generation, the SDT believes it is necessary to assess applicability on individual units greater than 20 MVA and aggregate generation greater than 75 MVA, which are thresholds that have been explicitly recognized and approved by FERC as appropriate thresholds for these types of facilities consistent with the revised BES definition.[3] The SDT therefore does not believe it would be appropriate to use different aggregation thresholds absent a robust technical justification to do so. Moreover, the SDT does not believe that a reliability gap is created, nor any unfair competitive advantages are given as a result, a position that is supported by clear industry consensus supporting the SDT's direction on these standards. Absent a clear technical justification compelling such a change, the SDT, after consulting with NERC's legal representative assigned to the project, respectfully declines to adopt the commenter's suggestion.

At least one commenter recommends revising 4.2.5 to read "Protection Systems for the following BES generator Facilities identified through Inclusions I2 and I3 of the BES definition," as the commenter believes it is more appropriate to cite how these BES generators are included under this section as opposed to indicating how they are not applicable under this section. Currently, according to the commenter, the standard's applicability is based first on the NERC Registration Criteria and secondly on facilities identified within the standard, regardless of their BES status. The commenter believes the proposed revisions mean to change the applicability of the standard first to the NERC Registration Criteria and secondly on facilities identified within the standard, and this BES generator Facilities

[3] *See* FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000.

change in 4.2.5 (i.e. Inclusions I2 and I3) essentially means the Protection System to be considered now is the “generator including the generator terminals through the high-side of the step-up transformer” and no longer considers protection to the point of interconnection.

The SDT believes the current language is adequate and clear. The SDT chose to use Inclusion I4 in the revised language of 4.2.5 such that the section 4.2.5 would resemble as closely as possible the original language of 4.2.5. Introducing the I2 and I3 terminology into this language was considered but determined to be unnecessary in order to specifically address DGRs. Furthermore, the SDT believes that further clarification of the applicability of the standard requirements to BES generators that are not identified under Inclusion I4 generators is beyond the scope of this project. The SDT disagrees that the revised language results in exclusion of the protection at the point of interconnection for these facilities, as this protection would be covered under 4.2.6.1. The SDT’s position is supported by clear industry consensus and it therefore respectfully declines to make the proposed changes.

B. PRC-005-3(X)

At least one commenter recommends revising 4.2.5 to read “Protection Systems for the following BES generator Facilities identified through Inclusions I2 and I3 of the BES definition,” as the commenter believes it is more appropriate to cite how these BES generators are included under this section as opposed to indicating how they are not applicable under this section.

The SDT believes the current language is adequate. The SDT chose to use Inclusion I4 in the revised language of 4.2.5 such that the section 4.2.5 would resemble as closely as possible the original language of 4.2.5. Introducing the I2 and I3 terminology into this language was considered, but determined to be unnecessary in order to specifically address dispersed power producing resources. The SDT believes that further clarification of the applicability of the standard requirements to BES generators that are not identified under Inclusion I4 generators is beyond the scope of this project.

At least one commenter believes that in order to minimize confusion regarding the use of the term “Facilities” versus “facilities” in the Applicability Section, the SDT should change the heading of 4.2 to “Applicable facilities.” The commenter also suggests that the formatting in 4.2.6 parallel the formatting, or construction, of 4.2.5 in that specifics are listed in 4.2.5 and they are absent in 4.2.6, or modify 4.2.5 to match 4.2.6. Another commenter believes that PRC-005-3(X) facilities sections (4.2.6 and 4.2.6.1) should be clarified and consistent with section 4.2.5 and offers suggested language to enhance clarity.

The SDT intends to refer to “Facilities” in the applicability section; this applicability section and the term “Facilities” is used in a number of standards to describe specific equipment that the standards’ requirements should be applied to. The scope of this SDT is to address the applicability to dispersed power producing resources only, and the SDT feels that changing this section to “facilities” would go beyond the scope of this project. The SDT chose not to list the specific Protection Systems in 4.2.6 like they are listed in 4.2.5, as the SDT believed the language in 4.2.6.1 (i.e., ". . . Facilities used in aggregating dispersed. . .") will result in inclusion of the appropriate Protections Systems for dispersed power producing facilities, a position supported by clear industry consensus. Therefore, the SDT respectfully declines to change its position.

C. PRC-005-X(X)

At least one commenter recommends revising 4.2.5 to read "Protection Systems for the following BES generator Facilities identified through Inclusions I2 and I3 of the BES definition," as the commenter believes it is more appropriate to cite how these BES generators are included under this section as opposed to indicating how they are not applicable under this section.

The SDT believes the current language is adequate. The SDT chose to use Inclusion I4 in the revised language of 4.2.5 such that the section 4.2.5 would resemble as closely as possible the original language of 4.2.5. Introducing the I2 and I3 terminology into this language was considered, but determined to be unnecessary in order to specifically address dispersed power producing resources. The SDT believes that further clarification of the applicability of the standard requirements to BES generators that are not identified under Inclusion I4 generators is beyond the scope of this project.

At least one commenter asks whether the reference to PRC-005-3 in the second line under the Description of Current Draft should be to PRC-005-4. The commenter notes that the redline version shows a rationale box with the Introduction section, and that this box, even though it contains redline changes, is not included in the clean version.

The reference to PRC-005-3 in the Description of Current Draft section is intended, as no released version of PRC-005-4 existed at the time of the posting of this project (2014-01). Upon further review, all rationale boxes in the redline version were incorporated into the clean version of the standard as well.

At least one commenter questions whether the omission of sudden pressure relays for dispersed generation resources under PRC-005-X Applicability 4.2.6 was intentional. It was not the intent of the SDT to omit sudden pressure relays on aggregating equipment at facilities with DGRs from the requirements listed in PRC-005-X. The SDT believes that sudden pressure relays utilized on Facilities associated with DGRs should be treated the same as those used on Facilities of other BES generators. The SDT will provide these comments to Project 2007-17.3 for consideration.

At least one commenter believes that sudden pressure relays are not "necessary." The scope of this SDT is to address the applicability to dispersed power producing resources only, not whether there is technical justification to include or exclude sudden pressure relays as a Protection System within the scope of PRC-005. The SDT believes that sudden pressure relays used on Facilities associated with DGRs should be treated the same as those used on Facilities of other BES generators. The SDT will provide these comments to Project 2007-17.3 for consideration.

4. Recommended Applicability Changes to VAR-002

Several commenters made comments that apply to both DGR versions of the posted VAR-002 standard, which the SDT addresses in this section. Although the SDT addresses industry comments specific to particular versions in the following sections, it considered each comment in the context of all versions of that particular standard to the extent applicable.

At least one commenter believes that the proposed changes are not consistent with the delineation in PRC-004 and PRC-005 nor inclusive of the DGR issue, and that VAR-002 changes only address change in reactive capability and do not address automatic voltage control and status at each generator site. The commenter suggests that VAR-002 should be written explicitly to only apply at the point of aggregation to 75 MVA with the transmission system.

The SDT is unaware of an automatic voltage control and status at each generator site issue. The SDT has proposed to exempt reporting of status or capability changes as stated in Requirement R3.1. to the DGR individual generating units identified through Inclusion I4 of the BES definition, but did not propose exemption from reporting at the aggregate facility level.

At least one commenter believes proposed R3 creates a reliability gap between I4 generators and I2 generators, and violates Section 303 of the NERC Rules of Procedure. The commenter suggests modifying the language to create a 20 MVA aggregation threshold for reporting. The SDT carefully considered this issue in responding to comments on its White Paper and these standards, and industry consensus clearly supports the SDT's recommendations on this standard, including Requirement R3. Absent clear industry consensus supporting the commenter's suggestion to modify the SDT's recommendations on VAR-002, the SDT has consulted with the NERC legal representative assigned to the project and respectfully declines to adopt the commenter's recommendation.

At least one commenter does not believe VAR-002 should state non-applicability to DGRs identified through Inclusion I4 of the BES definition and cites a number of factors specific to the WECC region, particularly with respect to modeling. The SDT agrees that modeling should be improved and inclusive of DGR facilities. However, VAR-002 deals with reporting of reactive power capability changes. Therefore, in light of clear industry consensus supporting the SDT's direction on VAR-002, the SDT respectfully declines to adopt the commenter's suggestion.

A. VAR-002-2b(X) [Note that FERC approved VAR-002-3 on August 1, 2014, and VAR-002-2b will be retired effective at midnight on September 30, 2014. The SDT is proceeding with balloting of

VAR-002-2b(X) because of differences in the way standards become enforceable in certain Canadian jurisdictions. The intent if VAR-002-2b(X) is approved by balloters is to file it upon Board adoption only in those Canadian jurisdictions that do not tie their enforcement dates to FERC approval.]

At least one commenter asks the SDT to clarify that Protection System Misoperations of the individual wind generators affects only themselves, but will not cause an aggregate effect with other wind turbines. For example, the commenter notes, this standard only applies to aggregate substation transformers. The commenter is concerned that still lies on meeting Requirements R1 and R2, operating in voltage control mode, and that some existing wind generators operate in a power factor control mode, not voltage control mode, and is not capable of operating in either voltage or power factor control mode.

The SDT believes Requirement R1 provides an exemption by the Transmission Operator, such as when "automatic voltage regulator" (AVR) is not required for older DGR facilities. Similarly, Requirement R2 has an exemption clause by the Transmission Operator. It is implied in NERC VAR-001-3 that each GOP and TOP should understand capabilities of the generation facility, including the equipment installed, said equipment's capabilities and the requirements of the transmission system to ensure a mutually agreeable solution and schedule are used.

At least one commenter notes that references to R4 and R5 in the Description of Current Draft Section should be to R3 and R4, and recommends deleting "BES" in front of "Bulk Electric Systems" referenced in the line in which the references are made. The SDT agrees and has therefore adopted these suggestions. The SDT believes the current language is sufficiently clear, and industry consensus supports the SDTs direction on this issue. Therefore, the SDT respectfully declines to adopt the commenter's suggestion.

At least one commenter suggests that the SDT modify R1 reasoning that each individual generating unit of a dispersed generation site that exceeds the 75 MVA threshold is included as part of the BES, and R1 would apply requiring each of these units to be operated with AVR in voltage regulating mode. According to the commenter, these units usually do not have an AVR and are not capable of controlling voltage; rather, they rely on other voltage regulating equipment such as SVC or capacitor banks to control voltage at the interconnecting point. Thus, the commenter requests that the SDT modify R1 so that is not applicable to the individual DGR units. The SDT believes the current language is sufficiently clear, and industry consensus supports the SDTs direction on this issue. Therefore, the SDT respectfully declines to adopt the commenter's suggestion.

At least one commenter believes R2 should also be modified to reflect that these DGRs often do not have AVRs and must rely on other voltage regulating equipment to control voltage at the interconnecting point, and that the SDT should modify R2 so that is not applicable to the individual DGR units.

The SDT does not agree that additional applicability changes are required for Requirements R1 and R2 because the AVR portion of the requirements cannot be applied to individual generators that do not have AVRs at each individual unit. Furthermore, each generation facility may have a different methodology to ensure the facility has an automatic and dynamic response to changes in voltage to ensure the TOPs instructions are maintained. It is implied in NERC VAR-001-3 that each GOP and TOP should understand the capabilities of the generation facility including the equipment installed, equipment capabilities, and the requirements of the transmission system to ensure that a mutually agreeable solution and schedule are used. Industry consensus supports the approach recommended by the SDT, and the SDT therefore respectfully declines to adopt the suggested changes to Requirements R1 and R2.

The SDT agrees with commenters that additional clarity is warranted in Requirement R3 and has therefore proposed changes as reflected in the posted redlined standard.

Some commenters agree with the SDTs recommended changes to Requirement R3, Part 3.1 but expresses their view that the number of individual units in an aggregated site is not detrimental to the overall operation of the entire site. In that case, according to the commenters, the site status for the entire aggregated facility should be reported. Many commenters further note that the Rationale Box for Footnote 5 references the Transmission Provider and in one instance only references Transmission, and that these references should be to the Transmission Planner as indicated in Requirement R4.

It was not the intent of the SDT to change the reporting requirements at the aggregate facility level. However, the SDT has made changes to the Requirement language to enhance clarity of the applicability to dispersed power producing resources. The SDT agrees the rationale for Requirement R4 should reference Transmission Operator and Transmission Planner and has therefore adopted that suggestion as reflected in the posted redlined standard.

At least one commenter agrees with the proposed Requirements but has issues with the associated Rational for Footnote 5 in Requirement R4, Part 4.1. The commenter believes auxiliary transformers stated in Requirement R4.1 are usually transformers that provide station services to the generator, and that the second sentence is out of line since it is directed to the collector system (34.5kV), which should be deleted. Another commenter suggests the SDT change “Transmission Provider” to “Transmission Planner.” The SDT agrees and has therefore made clarifying changes to the rationale box as reflected in the posted redlined standard.

At least one commenter argues that since the standard is being revised the SDT should make changes to re-align the Measures with the Requirements to develop a more risk-based standard as NERC has proposed going forward. The SDT expresses no opinion on this point, as the suggested change is outside the scope of this project.

B. VAR-002-4

At least one commenter notes that the bullet describing the DGR exclusion for R4 lacks identification of what "individual" is being excluded, and as written could create confusion. The commenter further notes that the rationale box indicates that the intent is to exclude the individual resources from R4, and suggests the following modification: "Reporting of reactive capability changes is not applicable to the individual resource for dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System Definition." The SDT believes that changes it has proposed in the posted redlined version of this standard are sufficiently clear.

At least one commenter believes the bulleted item under R4 is too wordy and recommends alternative language to provide clarity. The SDT has made clarifying changes as reflected in the posted redlined standard.

At least one commenter suggests inserting the term "generator" between "individual" and "for" in the bullet under Requirement R4. Another commenter notes that the rationale for R5 should identify the "Transmission Provider" to "Transmission Planner." The SDT agrees and has therefore made clarifying changes as reflected in the posted redlined standard.

Several commenters identify several errors in the posted version of this standard, specifically, Requirements R4 and R5. The SDT is aware the balloted version of VAR-002-4 was missing language in Requirement R4 and changed the requirement language in Requirement R5. The SDT has corrected these errors as reflected in the posted redlined standard.

At least one commenter believes that since VAR-002-4 only contains minor technical revisions dealing with the applicability specifically for Requirements R4 and R5, it may be feasible that VAR-002-4 will be approved before VAR-002-3, and the special provisions for 'the later of' are therefore not needed. The commenter believes the traditional Effective Date language would suffice. The commenter also believes that the concept of 'the first day of the first calendar quarter following approval' needs to be added to the governmental approval clause.

The SDT worked in close consultation with NERC staff to develop language that would result in DGR applicability changes as quickly as reasonably practicable regardless of which versions are first approved by FERC. Indeed, although FERC has approved VAR-002-3 and the standard will become enforceable in the U.S. on October 1, 2014, the Effective date language must allow for the different frameworks by which standards become enforceable in Canadian provinces. The SDT therefore respectfully declines to adopt the commenter's recommendation.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[4]

[4] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Granffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

10.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Michael Jones	National Grid	NPCC	1
13.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
16.	Lee Pedowicz	Northeast Power Coordinating Council		10
17.	Robert Pellegrini	the United Illuminating Company		1
18.	Ayesha Sabouba	Hydro One Networks Inc.		1
19.	Brian Robinson	Utility Services		8
20.	David Ramkalawan	Ontario Power Generation, Inc.		5
21.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
22.	Brian Shanahan	National Grid	NPCC	1
23.	Wayne Sipperly	New York Power Authority	NPCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

N/A

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Joseph DePoorter	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utiliteis	MRO	4

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

14. Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15. Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16. Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Connie Lowe	Dominion	X		X		X		X			

Additional Member	Additional Organization	Region	Segment Selection
1. Randi Heise		MRO	NA
2. Mike Garton		NPCC	5
3. Louis Slade		RFC	5, 6
4. Larry Nash		SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Michael Lowman	Duke energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils		RFC	1
2. Lee Schuter		FRCC	3
3. Dale Goodwine		SERC	5
4. Greg Cecil		RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Kathleen Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	NERC Compliance	RFC	3
2. Daniel Herring	NERC Training & Stanards Development	RFC	4
3. Mark Stefaniak	Generation Optimization	RFC	5
4. Barbara Holland	SOC		
5. Dave Szulczewski	DE-EE Relay Eng Supv		

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Cindy Stewart	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. William Smith	FirstEnergy Corp	RFC	1
2. Doug Hohlbaugh	Ohio Edison	RFC	4
3. Ken Dresner	FirstEnergy Solutions	RFC	5
4. Kevin Querry	FirstEnergy Solutions	RFC	7

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	David Greene	SERC Protection and Controls Subcommittee										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bridget Coffman	Santee Cooper		
2.	John Miller	GTC		
3.	George Pitts	TVA		
4.	Joel Masters	SCE&G		
5.	Steve Edwards	Dominion		
6.	David Greene	SERC		
7.	Paul Nauert	Ameren		

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Carol Chinn	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Service	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	4
8.	Don Cuevas	Beaches Energy Services	FRCC	1
9.	Mark Schultz	City of Green Cove Springs	FRCC	3
10.	Tom Reedy	Florida Municipal Power Pool	FRCC	6
11.	Steve Lancaster	Beaches	FRCC	1
12.	Richard Bachmeier	Gainesville Regional Utilities	FRCC	1
13.	Mike Blough	Kissimmee Utility Authority	FRCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
2.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
3.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
4.	Ron Losh	Southwest Power Pool	SPP	2
5.	Shannon Mickens	Southwest Power Pool	SPP	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6. Wes Mizzell	Westar Energy	SPP	1, 3, 5, 6										
7. James Nail	City of Independence, MO	SPP	3										
11.	Group	Greg Campoli	IRC Standards Review Committee		X								
Additional Member	Additional Organization	Region	Segment Selection										
1. Charles Yeung	SPP	SPP	2										
2. Ben Li	IESO	NPCC	2										
3. Ali Miremadi	CAISO	WECC	2										
4. Lori Spence	MISO	MRO	2										
5. Cheryl Moseley	ERCOT	ERCOT	2										
6. Matt Goldberg	ISONE	NPCC	2										
7. Stephanie Monzon	PJM	RFC	2										
12.	Group	Jason Marshall	ACES Standards Collaborators						X				
Additional Member	Additional Organization	Region	Segment Selection										
1. Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4										
2. Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5										
3. Ginger Mercier	Prairie Power	SERC	3										
4. Ellen Watkins	Sunflower Electric Power Corporation	SPP	1										
5. John Shaver	Arizona Electric Power Cooperative	WECC	4, 5										
6. John Shaver	Southwest Transmission Cooperative	WECC	1										
7. Bob Solomon	Hoosier Energy	RFC	1										
13.	Group	Pamela Hunter	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Southern Company Generation, Southern Company Generation and Energy Marketing	X		X		X	X				
N/A													
14.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				
Additional Member	Additional Organization	Region	Segment Selection										
1. Steve Enyeart	Customer Service Engineering	WECC	1										
15.	Individual	Heather Bowden	EDP Renewables North America LLC					X					
16.	Individual	Jim Nail`	Independence Power & Light			X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Individual	Joe Butterfield	Wisconsin Public Service Corporation			X							
18.	Individual	Terry Volkmann	Volkmann COnsulting, Inc								X		
19.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
20.	Individual	Anthony Jablonski	ReliabilityFirst										X
21.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
22.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X			X				
23.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
24.	Individual	Timothy Brown	Idaho Power	X									
25.	Individual	Karin Schweitzer	Texas Reliability Entity										X
26.	Individual	David Jendras	Ameren	X		X		X	X				
27.	Individual	John Pearson	ISO New England		X								
28.	Individual	John Robertson	First Wind					X					
29.	Individual	George Brown	Acciona Energy North America Corporation					X					
30.	Individual	Israel Beasley	Georgia Transmission Corporation	X									
31.	Individual	Joshua Andersen	Salt River Project	X		X		X	X				
32.	Individual	Steven Lancaster	BES			X							
33.	Individual	Spencer	Tacke			X	X		X				
34.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
35.	Individual	Michael Moltane	ITC	X									
36.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Agree	Supporting Comments of "Entity Name"
Independence Power & Light	Agree	Southwest Power Pool
BES	Agree	FMPA

1. **Do you agree with the revisions made in proposed PRC-005-2(X) to clarify applicability of PRC-005-2 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 1 Comment
MRO NSRF	No	The proposed wording within the Applicability section of 4.2.5 is very wordy and without the Rational box for 4.2.5, entities will be very confused. The NSRF recommend that 4.2.5 be reworded to read; "Protection Systems for BES generation Facilities (Inclusion I4 assets are contained within section 4.2.6)". This will allow all BES connected generators to be covered by this Standard and clearly describes what is applicable per Inclusion I4 via 4.2.6.
Dominion	No	Dominion recommends revising 4.2.5 to read "Protection Systems for the following BES generator Facilities identified through Inclusions I2 and I3 of the BES definition:" as we believe it is more appropriate to cite how these BES generators are included under this section as opposed to indicating how they are not applicable under this section. Currently the standard's applicability is based first on the NERC Registration Criteria and secondly on facilities identified within the standard (4.2.5 Protection Systems for generator Facilities), regardless of their BES status. This proposed revisions means to change the applicability of the standard first to the NERC Registration Criteria and secondly on facilities identified within the standard (4.2.5 Protection Systems for BES generator Facilities). This BES generator Facilities change in 4.2.5 (i.e. Inclusions I2 and I3) essentially means the Protection System to be considered now is the "generator including the

Organization	Yes or No	Question 1 Comment
		generator terminals through the high-side of the step-up transformer" and no longer considers protection to the point of interconnection.
FirstEnergy	No	FirstEnergy abstains as we are not directly impacted by this project. Please see our response to Question #6.
SPP Standards Review Group	No	Rewrite the 1st line under Description of Current Draft to read: 'This version of PRC-005 contains revisions to the applicability of the Standard intended to...' This eliminates the redline typo.In order to minimize confusion regarding the use of the term 'Facilities' versus 'facilities' in the Applicability Section, we recommend changing the heading of 4.2 to 'Applicable facilities'.Insert a space between the 'apply' and the 'only' in the 6th line of the Rationale Box for 4.2.6. Also expand the box down to capture all of the last line.We also suggest that the formatting in 4.2.6 parallel the formatting, or construction, of 4.2.5 in that specifics are listed in 4.2.5 and they are absent in 4.2.6. Or the drafting team could go in the other direction and modify 4.2.5 to match 4.2.6.The redline version contained several Rationale Boxes which are missing from the clean version. Were the boxes holdovers from previous versions making the clean version the correct copy or were they supposed to be included in the clean version?
EDP Renewables North America LLC	No	For consistency, it should be considered to have PRC-004 and PRC-005 to be applicable at an aggregate of greater than or equal to 75 MVA of BES facilities.
Wisconsin Public Service Corporation	No	The PRC-005-2(X) facilities sections (4.2.6 and 4.2.6.1) should be clarified and consistent with section 4.2.5. Suggested clarification: 4.2.6 Protection Systems for the following BES dispersed power producing resources identified through Inclusion I4 of the BES definition; excluding the individual resources: 4.2.6.1 Protection Systems that act to trip a common point of connection at 100 kV or above where those resources aggregate to greater

Organization	Yes or No	Question 1 Comment
		than 75 MVA, either directly or via a lockout relay. OR4.2.6.1 Protection Systems that act to trip dispersed power producing resources common point of connection at 100 kV or above where those resources aggregate to greater than 75 MVA, either directly or via lockout relay.
Public Service Enterprise Group	No	In 4.2.6.1, “75MVA should be changed to “20MVA.” This would make it comparable to I2 generators. Although the change to 20MVA would have this standard apply to non-BES assets, many standards do likewise. In fact “Protection Systems,” which are the subject of this standard, are non-BES. As written, a reliability gap would be created between I4 generators and I2 generators.The proposed change violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: “Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage.” If alternative language was proposed that required the same 75MVA threshold for I2 generators, PSEG would be fine with that. But the proposed non-comparable treatment of generators is not acceptable.
Hydro-Quebec TransEnergie	No	In Quebec, the RTP (Main Transmission System) Elements are applied instead of BES Elements. The Generation Facilities are greater than 50 MVA / 44kV instead of 75 MVA.Also in Quebec, NO Dispersed Generation is connected into the RTP network.To facilitate the compliance, the expression ‘inclusion I4’ should NOT include in the standard.
Idaho Power	No	Inclusion I4 of the BES definition specifically includes each generating resource. It is inconsistent to not include them for testing the protection systems under PRC-005. As written, there would be portions of the Bulk Electric System that would not be required to have the protection systems tested. A GO with a plant of small units aggregating above 75 MVA would be required to test the protection systems on all their units. How is this equitable? I understand that you have addressed this issue in the Consideration of Comments for the White Paper (Pg 9 & 10), however I

Organization	Yes or No	Question 1 Comment
		disagree with your conclusion. If they individual resources are insignificant to test, they why are they considered part of the BES?
ISO New England	No	Under the standard, a conventional generating resource has to have a documented protection maintenance program which it must follow to ensure reliability. On the other hand, under the proposed revisions to the standard, a similarly-sized, dispersed power producing resource would not be required to do the same. If the standard is not applied to the dispersed generation resource, then there is no required protection maintenance, which can (and does in practice) result in more frequent trips, and degraded reliability. Loss of the dispersed generation resource (as distinct from individual units) would have the same impact as loss of a single, similarly sized conventional generating resource. Thus, a maintenance program that applies beyond the common point of connection should be required. The maintenance program should definitely be tailored to the type of dispersed generation power producing resource as determined by the GO/GOP, but having no requirement in place does not ensure reliable operations.
Tacke	No	For all three PRC-005 proposed modifications, I think we still need to replace the 75 MVA generator size requirement with the 20 MVA size requirement, for the following reasons:WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed.Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV

Organization	Yes or No	Question 1 Comment
		units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2018.Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Duke energy	Yes	
DTE Electric	Yes	
SERC Protection and Controls Subcommittee	Yes	Please word the standard to clearly identify that PRC-005 becomes applicable on facilities where the aggregate generation sums to > 75MVA and it connects at >100kV. Please refer to Figures in the BES Definition Reference document to clearly identify the applicable facilities where the aggregate generation sums to > 75MVA and it connects at >100kV.For example in the BES Definition Reference Document Figures I4-1 through I4-4, is the protection system on the blue bus in the purple circle included given that the green feeders are not BES? Or, is just the transformer protection applicable since it is clearly all blue (BES) in the diagram?As another example in the BES Definition Reference Document Figure I4-1, can each of the 4 green strings of distributed generation be owned by the same or different companies, located at one or separate locations and the blue collector bus actually be a sub transmission line (or distribution line)?

Organization	Yes or No	Question 1 Comment
Florida Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
ACES Standards Collaborators	Yes	We agree with the changes.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Southern Company Generation, Southern Company Generation and Energy Marketing	Yes	The drafting team has identified the appropriate aggregation point for dispersed power producing resources.
Bonneville Power Administration	Yes	This approach relies on maintenance practices of individual generators and collector systems before reaching the aggregation points as provided by the generator owner. This is in their best interest and in the best interest of the industry.
Volkmann COnsulting, Inc	Yes	
American Electric Power	Yes	
Manitoba Hydro	Yes	
Texas Reliability Entity	Yes	
Ameren	Yes	Ameren adopts the SERC PCS comments by reference
First Wind	Yes	Applicability is adequate for reliability.
Acciona Energy North America Corporation	Yes	

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation	Yes	
Salt River Project	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	4.2.5 is written strangely. "Protection Systems for the following BES generator Facilities not identified through Inclusion I4 of the BES definition" reads better.
Sacramento Municipal Utility District	Yes	Please clarify whether Protection System Maintenance only applies to the aggregate transformers, but not the individual wind generators and its respective step-up transformers.

2. Do you agree with the revisions made in proposed PRC-005-3(X) to clarify applicability of PRC-005-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 2 Comment
MRO NSRF	No	See comments per question 1.
Dominion	No	Dominion recommends revising 4.2.5 to read "Protection Systems for the following BES generator Facilities identified through Inclusions I2 and I3 of the BES definition:" as we believe it is more appropriate to cite how these BES generators are included under this section as opposed to indicating how they are not applicable under this section.
FirstEnergy	No	FirstEnergy abstains as we are not directly impacted by this project. Please see our response to Question #6.
SPP Standards Review Group	No	In order to minimize confusion regarding the use of the term 'Facilities' versus 'facilities' in the Applicability Section, we recommend changing the heading of 4.2 to 'Applicable facilities'.We also suggest that the formatting in 4.2.6 parallel the formatting, or construction, of 4.2.5 in that specifics are listed in 4.2.5 and they are absent in 4.2.6. Or the drafting team could go in the other direction and modify 4.2.5 to match 4.2.6.
EDP Renewables North America LLC	No	For consistency, it should be considered to have PRC-004 and PRC-005 to be applicable at an aggregate of greater than or equal to 75 MVA of BES facilities.

Organization	Yes or No	Question 2 Comment
Wisconsin Public Service Corporation	No	The PRC-005-3(X) facilities sections (4.2.6 and 4.2.6.1) should be clarified and consistent with section 4.2.5. Suggested clarification: 4.2.6 Protection Systems for the following BES dispersed power producing resources identified through Inclusion I4 of the BES definition; excluding the individual resources: 4.2.6.1 Protection Systems that act to trip a common point of connection at 100 kV or above where those resources aggregate to greater than 75 MVA, either directly or via a lockout relay. OR4.2.6.1 Protection Systems that act to trip dispersed power producing resources common point of connection at 100 kV or above where those resources aggregate to greater than 75 MVA, either directly or via lockout relay.
Public Service Enterprise Group	No	The same comments in Q1 apply.
Hydro-Quebec TransEnergie	No	See response in question 1
Idaho Power	No	See discussion in #1.
ISO New England	No	See response for Question 1
Tacke	No	For all three PRC-005 proposed modifications, I think we still need to replace the 75 MVA generator size requirement with the 20 MVA size requirement, for the following reasons:WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed.Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line

Organization	Yes or No	Question 2 Comment
		between now and 2018.Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Duke energy	Yes	
DTE Electric	Yes	
SERC Protection and Controls Subcommittee	Yes	See comments with Question 1.
Florida Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
ACES Standards Collaborators	Yes	We agree with the changes.
Southern Company: Southern Company Services, Inc.; Alabama Power Company;	Yes	The drafting team has identified the appropriate aggregation point for dispersed power producing resources.

Organization	Yes or No	Question 2 Comment
Southern Company Generation, Southern Company Generation and Energy Marketing		
Bonneville Power Administration	Yes	This approach relies on maintenance practices of individual generators and collector systems before reaching the aggregation points as provided by the generator owner. This is in their best interest and in the best interest of the industry.
Volkmann COnsulting, Inc	Yes	
American Electric Power	Yes	
Manitoba Hydro	Yes	
Texas Reliability Entity	Yes	
Ameren	Yes	Ameren adopts the SERC PCS comments by reference
First Wind	Yes	Applicability is adequate for reliability.
Acciona Energy North America Corporation	Yes	
Georgia Transmission Corporation	Yes	The only comments I would suggest are fixing the wording in the Automatic Reclosing section 4.2.7.2 of PRC-005-3/PRC-005-X to refer to section 4.2.7.1 instead of 4.2.6.1. It appears this change was simply overlooked.
Salt River Project	Yes	

Organization	Yes or No	Question 2 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	4.2.5 is written strangely. "Protection Systems for the following BES generator Facilities not identified through Inclusion I4 of the BES definition" reads better.
Sacramento Municipal Utility District	Yes	

3. **Do you agree with the revisions made in proposed PRC-005-X(X) to clarify applicability of PRC-005-X (the version of PRC-005 containing revisions to address Sudden Pressure relays, being developed in Project 2007-17.1) to dispersed power-producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes**

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 3 Comment
MRO NSRF	No	See comments per question 1.
Dominion	No	Dominion recommends revising 4.2.5 to read "Protection Systems for the following BES generator Facilities identified through Inclusions I2 and I3 of the BES definition:" as we believe it is more appropriate to cite how these BES generators are included under this section as opposed to indicating how they are not applicable under this section.
FirstEnergy	No	FirstEnergy abstains as we are not directly impacted by this project. Please see our response to Question #6.
SPP Standards Review Group	No	Shouldn't the reference to PRC-005-3 in the 2nd line under the Description of Current Draft be to PRC-005-4?The redline version shows a Rationale Box with the Introduction Section. This box, even though it contains redline changes, is not included in the clean version. Were the redline changes holdovers from a previous version and should not have been shown in this redline or were they supposed to be included in the clean version?In order to minimize confusion regarding the use of the term 'Facilities' versus 'facilities' in the Applicability Section, we recommend changing the heading of 4.2 to 'Applicable facilities'.The page header includes the PRC-005-4(X) label while within the standard itself it is shown as PRC-005-X. Which is correct?We would also suggest that the formatting in 4.2.6 parallel the formatting, or construction, of 4.2.5 in that specifics are listed in 4.2.5 and they are absent in 4.2.6. Or the drafting team could go in the other direction and modify

Organization	Yes or No	Question 3 Comment
		4.2.5 to match 4.2.6.The Rationale Boxes for 4.2.5 and 4.2.6 cover-up text. The boxes need to be moved such that they do not cover-up any text.
EDP Renewables North America LLC	No	For consistency, it should be considered to have PRC-004 and PRC-005 to be applicable at an aggregate of greater than or equal to 75 MVA of BES facilities.
Wisconsin Public Service Corporation	No	The PRC-005-X(X) facilities sections (4.2.6 and 4.2.6.1) should be clarified and consistent with section 4.2.5. Suggested clarification: 4.2.6 Protection Systems for the following BES dispersed power producing resources identified through Inclusion I4 of the BES definition; excluding the individual resources: 4.2.6.1 Protection Systems that act to trip a common point of connection at 100 kV or above where those resources aggregate to greater than 75 MVA, either directly or via a lockout relay. OR4.2.6.1 Protection Systems that act to trip dispersed power producing resources common point of connection at 100 kV or above where those resources aggregate to greater than 75 MVA, either directly or via lockout relay. In addition, there should be further clarification surrounding the inclusion/exclusion of the sudden pressure relay.
Public Service Enterprise Group	No	The same comments in Q1 apply.
Idaho Power	No	See discussion in #1.
ISO New England	No	See response for Question 1
Salt River Project	No	Sudden pressure relays are not "necessary", in fact, older transformers will likely not have them. What is necessary for "reliable operation" as defined in the statute are the differential relays, overcurrent relays, etc., that are there to clear a major phase to phase or phase to ground fault that if left uncleared can cause instability. A sudden pressure relay is there primarily for equipment health monitoring, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault.
Tacke	No	For all three PRC-005 proposed modifications, I think we still need to replace the 75 MVA generator size requirement with the 20 MVA size requirement, for the following reasons:WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed.Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large

Organization	Yes or No	Question 3 Comment
		percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2018.Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Duke energy	Yes	
DTE Electric	Yes	
SERC Protection and Controls Subcommittee	Yes	See comments with Question 1.
Florida Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
ACES Standards Collaborators	Yes	We agree with the changes.
Bonneville Power Administration	Yes	This approach relies on maintenance practices of individual generators and collector systems before reaching the aggregation points as provided by the generator owner. This is in their best interest and in the best interest of the industry.
Volkmann COnsulting, Inc	Yes	
American Electric Power	Yes	Was the omission of sudden pressure relays for dispersed generation resources under PRC-005-X Applicability 4.2.6 intentional? In light of the FERC directive associated with SPRs, we are unsure if FERC will accept a version of the standard that does not require testing of SPRs for transformers connected between the point that the resources aggregate to greater than 75 MVA and the point of interconnection.
Manitoba Hydro	Yes	
Texas Reliability Entity	Yes	

Organization	Yes or No	Question 3 Comment
Ameren	Yes	Ameren adopts the SERC PCS comments by reference
First Wind	Yes	Applicability is adequate for reliability.
Acciona Energy North America Corporation	Yes	
Georgia Transmission Corporation	Yes	The only comments I would suggest are fixing the wording in the Automatic Reclosing section 4.2.7.2 of PRC-005-3/PRC-005-X to refer to section 4.2.7.1 instead of 4.2.6.1. It appears this change was simply overlooked.
Tri-State Generation and Transmission Association, Inc.	Yes	4.2.5 is written strangely. "Protection Systems for the following BES generator Facilities not identified through Inclusion I4 of the BES definition" reads better.
Sacramento Municipal Utility District	Yes	

4. Do you agree with the revisions made in proposed VAR-002-2b(X) to clarify applicability of VAR-002-2b to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 4 Comment
MRO NSRF	No	The NSRF agrees with the proposed Requirements but has issues with the associated Rational for Footnote 5 in R4, Part 4.1, note that Transmission Provider should be Transmission Planner. The auxiliary transformers stated in R4.1 are usually transformers that provide station services to the generator. The first sentence of the Ration is correct. The second sentence is out of line since it is directed to the collector system (34.5kV), this should be deleted. This rewrite will provide simple clarity that the foot note is trying to provide.
FirstEnergy	No	FirstEnergy abstains as we are not directly impacted by this project. Please see our response to Question #6.
SPP Standards Review Group	No	References to R4 and R5 in the Description of Current Draft Section should be to R3 and R4. Also delete the BES in front of Bulk Electric Systems in the line in which the references are made.The proposed change to Requirement R3, Part 3.1 is okay as long as the number of individual units in an aggregated site is not detrimental to the overall operation of the entire site. In that case, the site status, for the entire aggregated facility, should be reported. If this is the intent of Part 3.2, it needs additional clarification to make it stand out.The Rationale Box for Footnote 5

Organization	Yes or No	Question 4 Comment
		references the Transmission Provider and in one instance only references Transmission. We believe these references should be to the Transmission Planner as indicated in Requirement R4.
Volkmann COnsulting, Inc	No	The change is neither consistent with the delineation in PRC-004 / 5 nor inclusive of the dispersed generation issue. My interpretation is that VAR-002 change only address change in reactive capability and does not address automatic voltage control and status at each generator site. VAR-002 should be written explicitly to only applicable at the point of aggregation to 75 MVA with the transmission system.
Public Service Enterprise Group	No	How does one interpret the added “bullet” in R3? The new bullet statement belongs in the Applicability section. Furthermore, the statement creates a reliability gap between I4 generators and I2 generators. It also violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: “Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage.” We suggest the following addition to the bullet to correct both issues (added language is CAPITALIZED): “.... Bulk Electric Definition; HOWEVER, REPORTING CHANGES ARE REQUIRED AT THE POINT THAT INDIVIDUAL INCLUSON I4 BES GENERATORS AGGREGATE TO GREATER THAN 20MVA.”
Hydro-Quebec TransEnergie	No	See response in question 1
Tacke	No	For both VAR-002 proposed modifications, I don’t think we should state non-applicability of the Standard for dispersed generation resources indentified through Inclusion I4 of the BES definition, for the following reasons: WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed.Also, within the next few years,

Organization	Yes or No	Question 4 Comment
		there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2018.Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Dominion	Yes	Rationale for R4, need to change Transmission Provider to ‘Transmission Planner’.Since this standard is being revised, Dominion suggests that NERC request the SDT to re-align the Measures with the Requirements to develop a more risk-based standard as NERC has proposed going forward.
Duke energy	Yes	Duke Energy suggests the following revision:”Reporting of status or capability changes is not applicable to the individual dispersed power producing resources identified through Inclusion I4 (a) of the Bulk Electric System definition.”We believe the addition of “I4 (a)” helps clarify the applicability for individual dispersed power producing resources.
DTE Electric	Yes	

Organization	Yes or No	Question 4 Comment
ACES Standards Collaborators	Yes	(1) We agree with the proposed changes. However, we believe additional changes are needed to the standard.(2) Requirement R1 needs to be modified as well. Because each individual generating unit of a dispersed generation site that exceeds the 75 MVA threshold is included as part of the BES, R1 would apply and would require each of these units to be operated with AVR in voltage regulating mode. These units usually do not have an AVR and are not capable of controlling voltage. Rather, they rely on other voltage regulating equipment such as SVC or capacitor banks to control voltage at the interconnecting point. Thus, we request that R1 is modified so that is not applicable to the individual units of the dispersed power producing resources. (3) Similar to R1, R2 should also be modified to reflect that these dispersed generation resources often do not have AVRs and must rely on other voltage regulating equipment to control voltage at the interconnecting point. Thus, we request that R2 is modified so that is not applicable to the individual units of the dispersed power producing resources.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Southern Company Generation, Southern Company Generation and Energy Marketing	Yes	
Bonneville Power Administration	Yes	
EDP Renewables North America LLC	Yes	

Organization	Yes or No	Question 4 Comment
Wisconsin Public Service Corporation	Yes	
ReliabilityFirst	Yes	ReliabilityFirst submits the following comments for consideration:1. VAR-002-2b(X) Requirement 3, Part 3.1 - The exclusion for dispersed power producing resources is shown as a bullet point and bullet points are historically described as “OR” statements in NERC Reliability Standards. ReliabilityFirst recommends adding the bulleted language to the end of Requirement 3, Part 3.1 as follows: “A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability. Reporting of status or capability changes is not applicable to the individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.”
American Electric Power	Yes	
Manitoba Hydro	Yes	
Idaho Power	Yes	
Texas Reliability Entity	Yes	
Ameren	Yes	
First Wind	Yes	
Acciona Energy North America Corporation	Yes	
Salt River Project	Yes	

Organization	Yes or No	Question 4 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
Sacramento Municipal Utility District	Yes	: Please clarify that Protection System Misoperations of the individual wind generators affects only themselves, but will not cause an aggregate effect with other wind turbines. For example, this standard only applies to aggregate substation transformers. There is a concern that still lies on meeting requirements R1 and R2, operating in voltage control mode. Some existing wind generators operate in a power factor control mode, not voltage control mode, and is not capable of operating in either voltage or power factor control mode.
SERC Protection and Controls Subcommittee		no comment
Florida Municipal Power Agency		In the rationale for Footnote 5 in Requirement R4, Part 4.1 the references to Transmission Provider should be Transmission Planner. The reference to “Transmission” should be Transmission Planner.
IRC Standards Review Committee		The proposed change to Requirement R3, Part 3.1 is okay as long as the net change to number of the individual units in an aggregated site is not detrimental to affect the overall operation of the entire site or the proper management and control of reactive resources of the site. In that case, the site status, for the entire aggregated facility, should be reported. If this is the intent of Part 3.2 is intended to cover the latter situation (where the impact of changes to individual disperse generating sources is reported at the aggregate level), then Part 3.2 needs , it needs additional to be expanded to clarify it. clarification to make it stand out. Otherwise, the impact of changes to individual units will not be identified and reported for control to meet the objective of control and management of reactive resources.The Rationale Box for Footnote 5 references the Transmission Provider and in one instance only references

Organization	Yes or No	Question 4 Comment
		Transmission. We believe these references should be to the Transmission Planner as indicated in Requirement R4.

5. Do you agree with the revisions made in proposed VAR-002-4 to clarify applicability of VAR-002-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 5 Comment
MRO NSRF	No	The bulleted item under R4 is too wordy and recommend the following rewrite to provide clarity; "Reporting of reactive capability changes is not applicable to (delete "the") individual (delete "for ") dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.
FirstEnergy	No	FirstEnergy abstains as we are not directly impacted by this project. Please see our response to Question #6.
SPP Standards Review Group	No	Since VAR-002-4 only contains minor technical revisions dealing with the applicability specifically for Requirements R4 and R5, is it feasible to believe that VAR-002-4 will be approved before VAR-002-3? The special provisions for 'the later of' aren't

Organization	Yes or No	Question 5 Comment
		needed. Simply go with the normal Effective Date language. Additionally, the way this section is currently worded in those jurisdictions requiring governmental approval, the standard becomes effective immediately upon governmental approval. Yet, if governmental approval is not required, the standard would become effective the first day of the first calendar quarter following NERC Board approval. The concept of 'the first day of the first calendar quarter following approval' needs to be added to the governmental approval clause.The same argument applies to the proposed change for Requirement R4 as we put forth in response to the proposed change to Requirement R3, Part 3.1 in VAR-002-2b(X) in Question 4. The proposal is okay provided that only lost capability of a few individual units does not detract from the overall capability of the entire aggregated site. If the capability of the entire site is degraded the notification should be made. Also, insert the term 'generator' between 'individual' and 'for' in the bullet under Requirement R4.Requirement R5 is a duplicate of Requirement R4 and needs to be replaced with the correct wording from VAR-002-2b(X), Requirement R4.The clean version is missing the Rationale Box for Footnote 5.
Volkmann COnsulting, Inc	No	see question 4
Public Service Enterprise Group	No	The same comments in Q3 apply, except replace "R3" with "R4."
Hydro-Quebec TransEnergie	No	See response in question 1
Ameren	No	(1) Regarding proposed standard VAR-002-4, we believe that some language is missing for requirement R5.1. Shouldn't the requirement state that the Generator Operator needs to provide the information on Tap Settings, Available fixed tap ranges, and Impedance data to the Transmission Operator?(2) We believe that VAR-002-4 should include a 30 day time period to complete R5, as alluded to in M5.

Organization	Yes or No	Question 5 Comment
Acciona Energy North America Corporation	No	I agree with the intent of the SDT, however, the balloted version VAR-002-4 is incorrect.VAR-002-4 R4: added applicability clause is incorrect and misworded VAR-002-4 R5: Requirement is incorrect and not original requirement from version 3 of this standard
Tacke	No	For both VAR-002 proposed modifications, I don't think we should state non-applicability of the Standard for dispersed generation resources indentified through Inclusion I4 of the BES definition, for the following reasons: WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed.Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2018.Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 5 Comment
Dominion	Yes	Rationale for R5, need to change Transmission Provider to 'Transmission Planner'.
Duke energy	Yes	Duke Energy suggests the following revision:"Reporting of reactive capability changes is not applicable to the individual dispersed power producing resources identified through Inclusion I4 (a) of the Bulk Electric System definition."We believe the addition of "I4 (a)" helps clarify the applicability for individual dispersed power producing resources. We would also like to point out an apparent typo in R4 and suggest modifying "individual for dispersed power producing resources" to" individual dispersed power producing resources". The removal of "for" provides consistency with the language in VAR-002-2b.
DTE Electric	Yes	
IRC Standards Review Committee	Yes	
ACES Standards Collaborators	Yes	(1) We agree with the proposed changes. However, we believe additional changes are needed to the standard.(2) Requirement R1 needs to be modified as well. Because each individual generating unit of a dispersed generation site that exceeds the 75 MVA threshold is included as part of the BES, R1 would apply and would require each of these units to be operated with AVR in voltage regulating mode. These units usually do not have an AVR and are not capable of controlling voltage. Rather, they rely on other voltage regulating equipment such as SVC or capacitor banks to control voltage at the interconnecting point. Thus, we request that R1 is modified so that is not applicable to the individual units of the dispersed power producing resources. (3) Similar to R1, R2 should also be modified to reflect that these dispersed generation resources often do not have AVRs and must rely on other voltage regulating equipment to control voltage at the interconnecting point. Thus, we request that R2 is modified so that is not applicable to the individual units of the dispersed power producing resources.

Organization	Yes or No	Question 5 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Southern Company Generation, Southern Company Generation and Energy Marketing	Yes	
Bonneville Power Administration	Yes	
EDP Renewables North America LLC	Yes	
Wisconsin Public Service Corporation	Yes	
American Electric Power	Yes	
Manitoba Hydro	Yes	
Idaho Power	Yes	
Texas Reliability Entity	Yes	1)Texas RE agrees with the change to applicability but points out that there may be an error in the language of R5 of VAR-002-4. Requirement 4 and 5 have the exact same requirement language:"Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability."Requirement 5

Organization	Yes or No	Question 5 Comment
		goes on to add: “For generator step-up transformers and auxiliary transformers5 with primary voltages equal to or greater than the generator terminal voltage:5.1.1. Tap settings.5.1.2. Available fixed tap ranges.5.1.3. Impedance data. The requirements in VAR-002-2b (R4) and VAR-002-3 (R5) that include the tap settings, ranges and impedance data language have the following requirement language:”The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.” Texas RE requests the SDT review the language to assure the correct requirement language is included in Requirement R5 of VAR-002-4.2)It appears that R7 of VAR-002-4 should actually be the Measure for R6, not a Requirement. 3)It appears that VAR-002-2b(X) Requirement R3.1 and VAR-002-4 Requirement R4 map to each other but the exclusion language is slightly different. VAR-002-4, R4 has the word “for” between “individual” and “dispersed power” whereas VAR-002-2b(X) does not. The addition of the word makes the requirement confusing. It may just be a typo but Texas RE wanted to bring this to the attention of the SDT. VAR-002 -2b(X) Requirement R3.1 language: Reporting of status or capability changes is not applicable to the individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. VAR-002-4 Requirement R4 language: Reporting of reactive capability changes is not applicable to the individual for dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.
First Wind	Yes	
Salt River Project	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	"R7" should be "M6". The effective date is confusing as written and makes it seem as if the standard would be effective immediately. Was that the SDT's intentions? Since VAR-002-3 is still waiting on FERC approval and is not effective yet the industry should have some time to prepare for VAR-002-4.

Organization	Yes or No	Question 5 Comment
SERC Protection and Controls Subcommittee		no comment
Florida Municipal Power Agency		In the added bullet to R4, the word “for” should be deleted. In the rationale for Footnote 5 in Requirement R5, Part 5.1 the references to Transmission Provider should be deleted. The reference to “Transmission” should be deleted. Although not in the scope of this particular SDT, the reference to Transmission Planner in M5 should be deleted since notification is not required by R5.

6. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

Summary Consideration: The SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	No	
Arizona Public Service Company	No	
DTE Electric	No	
SERC Protection and Controls Subcommittee	No	The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and

Organization	Yes or No	Question 6 Comment
		should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Florida Municipal Power Agency	No	
ACES Standards Collaborators	No	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Southern Company Generation, Southern Company Generation and Energy Marketing	No	
Bonneville Power Administration	No	
Wisconsin Public Service Corporation	No	
Volkmann COnsulting, Inc	No	
Public Service Enterprise Group	No	
American Electric Power	No	
Manitoba Hydro	No	

Organization	Yes or No	Question 6 Comment
Hydro-Quebec TransEnergie	No	
Texas Reliability Entity	No	
Ameren	No	
First Wind	No	
Acciona Energy North America Corporation	No	
Salt River Project	No	
Tacke	No	
Tri-State Generation and Transmission Association, Inc.	No	
MRO NSRF	Yes	Please note that NERC has already written a proposed Guidance document on these Standards, including PRC-004. The NSRF, request that the SDT coordinate with NERC so that any Standard and Guidance document complement each other.
Dominion	Yes	Dominion, from a philosophical perspective, cannot support a continent-wide standard (VAR-002) that does not grant a waiver (or waivers) where one or more approved regional standard exists. We cite the following as reason supporting this philosophy; PRC-006, Docket # RM11-20 - In Order No. 763 (issued on May 7, 2012), the Commission directed NERC to submit a Compliance Filing regarding several aspects including how it will address the Commission's directive to establish a schedule by the planning coordinator to comply with PRC-006-1 Requirement R9. In its compliance filing, NERC stated that an entity must be compliant with both the continent wide PRC-006 Standard and the regional standard proposed by SERC in

Organization	Yes or No	Question 6 Comment
		Docket No. RM12-9. Dominion intervened requesting that the Commission modify Requirement R6 to require each UFLS entity in the SERC Region to implement changes to the UFLS scheme within the lesser of 18 months of notification by the planning coordinator, or the schedule established by the planning coordinator. In reply to SERC's responsive comments, Dominion disagrees that its concerns have been adequately addressed. Dominion states that "it is unjust to hold a registered entity responsible for compliance to any requirement within a reliability standard where such compliance is dependent upon that registered entity having also read, and taken into consideration, all statements issued by FERC, NERC and the Regional Entity. The Commission declined Dominion's request and instead affirmed the interpretation as set forth in NERC and SERC's comments.PRC-002-2 - NPCC received approval of its regional standard (PRC-002-NPCC-01) in October 2011. That standard also contained an implementation plan which provides staggered effective dates, i.e., the date on which applicable entities are subject to mandatory compliance, with full compliance required within four years of regulatory approval. During the comment period, Dominion stated potential for conflict between the approved regional standard and the draft continent-wide standard, and also noted that registered entities in that region are 2 years into the 4 year implementation which creates uncertainty for NPCC applicable entities. The drafting team's response did not adequately address Dominion's concerns.Dominion does not agree with the response provided by the SDT relative to comments related to PRC-006, specifically the regional (NPCC and SERC) versions. Both of these approved regional standards apply to Generator Owner and we therefore agree that the SDT should include the continent wide standard in its review.
Duke energy	Yes	PRC-005 Implementation Plans: We suggest removing "first day following" in all the PRC-005 implementation plans. It appears that as written, there could be a gap between the effective date and retirement date of these standards.VAR-002-2b RSAW : We suggest adding I4 (a) to the R3 Note To Auditor Section of the RSAW for consistency with our comments to Question 4 as follows:"Requirement R3.1 is not applicable to individual dispersed power producing resources identified through

Organization	Yes or No	Question 6 Comment
		Inclusion I4 (a) of the Bulk Electric System definition. Entity assertions regarding applicability of Requirement R3.1 should be supported by evidence such as one-line diagrams, nameplate ratings, manufacturer information, or BES inclusion documentation available at the Regional Entity."VAR-002-3 RSAW : We suggest adding I4 (a) to the R4 Note To Auditor Section of the RSAW with our comments to Question 5 as follows:"Requirement R4 is not applicable to the individual dispersed power producing resources identified through Inclusion I4 (a) of the Bulk Electric System definition. Entity assertions regarding applicability of Requirement R4 should be supported by evidence such as one-line diagrams, nameplate ratings, manufacturer information, commissioning tests, etc."
FirstEnergy	Yes	FirstEnergy abstains as we are not directly impacted by this project. We question the efficiency of modifying several NERC Reliability Standards in lieu of potentially adjusting the NERC BES definition which may more effectively address the concerns. Additionally there are other revisions to the NERC BES definition needed in regard to generation assets. As written, there is inequality in the NERC BES definition for traditional generation resources versus dispersed generation. A single traditional unit of 25 MVA must meet all NERC Reliability Standards that apply to Generator Owners yet for the dispersed generation they are only subject to the extent that they total 75 MVA or more.When there are standards before FERC pending regulatory approval, all subsequent revisions should be based on the latest NERC Board approved version. It is our opinion that the approach taken to modify and post for ballot several versions of the same standard is inefficient, overly complicated and unnecessarily causes industry confusion. We suggest that the NERC Standards Committee reassess the need to make this a standalone project and work the intended revisions into current ongoing projects.
SPP Standards Review Group	Yes	The various Implementation Plans for each version of PRC-005 are cross referenced in the Implementation Plans for PRC-005-2(X), PRC-005-3(X) and PRC-005-X(X) in this project. We suggest a change in language to an item in the Background Section of each of those referenced Implementation Plans. We propose the following: '2. For

Organization	Yes or No	Question 6 Comment
		entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program. Those entities which now fall under the requirements of the standard due to BES definition changes would have twenty-four months from the applicable effective date to demonstrate compliance.' This would eliminate the potential for a repeat of the fiasco of a few years back associated with implementation of PRC-005-1 in which evidence of compliance was required prior to the effective date of the standard. There is inconsistency among the proposed standards on the term dispersed power producing facilities. In some instances power producing is hyphenated, in others it is not. In some instances facilities is capitalized, in others it is not. The SDT needs to determine which is correct and stick to it.There is inconsistency among the proposed standards on the use of the terms 75 MVA and 100 kV. In some instances they are shown with the space and in others they are shown without the space as 75MVA and 100kV. The SDT, again, needs to determine which is correct and stick to it.
ISO New England	Yes	In PRC-005-2(X), under A.2, the number "2" should not have been deleted and the letter "X" should be in parenthesis as it is shown in the header.In PRC-005-2(X), and VAR-002-2b(X), under D. Compliance 1.1 - It is not necessary to repeat the definition of Compliance Enforcement Authority. A reference to the NERC Rules of Procedure is sufficient. The benefit is that, if the definition ever changes there, it will not have to be changed here. Therefore, 1.1 under Compliance should simply say: "Compliance Enforcement Authority" has the meaning ascribed to it in the NERC Rules of Procedure.
Georgia Transmission Corporation	Yes	The only comments I would suggest are fixing the wording in the Automatic Reclosing section 4.2.7.2 of PRC-005-3/PRC-005-X to refer to section 4.2.7.1 instead of 4.2.6.1. It appears this change was simply overlooked.

Organization	Yes or No	Question 6 Comment
ITC	Yes	Regarding VAR-002, ITC makes the following comments:The Standard should define dispersed power producing resource. While in a practical sense this is a facility comprised of wind turbines or PV inverters, offering exclusions from Requirements based on an undefined criteria is not a good practice.R4 - ITC recommends removal of the sub-bullet under R4 excluding the generators identified through Inclusion I4. The exclusion using BES I4 is confusing and may conflict with existing standard VAR-001-4. A non-BES unit or several non-BES units combined together could have an impact on the BES and thus removing the generators from VAR-002-4 R4 solely based on Inclusion I4 may be detrimental to reliability. Per VAR-001-4 R4, the TOP is required to specify criteria that will exempt generators from following a voltage or reactive power schedule and associated notification requirements. Therefore, ITC recommends that VAR-002-3 R4 should be reworded as “Unless exempted by the Transmission Operator, each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement 3”. The TOP can determine what notifications are necessary and be more specific depending on the needs of the system or individual facility. For example, a TOP exemption criteria may contain: “Dispersed power producing facilities are exempt from reactive capability change notifications less than 10% of the total aggregate lagging reactive capability as measured at the POI at nominal voltage”. TOPs typically will not want to receive individual turbine outage notifications; however, there may be instances where a dispersed power producing resource could lose an individual unit that may affect reliable operations (i.e. large individual units). In addition, the sub-bullet language in VAR-002-4 may be interpreted such that generators not in BES are exempt from reactive capability notifications and, in turn, exempt from following schedules which may be in conflict with VAR-001-4 and potentially impact the reliability of the BES. VAR-001-4 requires the TOP to determine the exemption criteria for generators and ITC recommends that VAR-002-4 be consistent with this practice as the TOP may require non-BES generators to follow a voltage or reactive power schedule based on the collective impact to the BES.R5 - The language in VAR-

Organization	Yes or No	Question 6 Comment
		002-4 R5 is a repeat of the VAR-002-4 R4 language and does not correspond to sub-requirement R5.1 . Replace with appropriate R5 language from VAR-002-3. Similar to R4, the exclusion shouldn't be based on BES I4. ITC recommends the footnote is reworded to: "For dispersed power producing resources, this requirement applies only to those transformers that have at least one winding at the same or higher voltage as the lowest voltage Point of Interconnection location(s)."
Sacramento Municipal Utility District	Yes	Comment 1: These revisions are logical and simply needed to clarify applicability. In fact, not approving these revisions may be detrimental to reliability or not useful to the support of the reliable operation of the BES. Moreover, preparing for implementation under the chance the revisions are not approved is diverting time and resources that could otherwise be devoted to efforts that do contribute to the reliable operation of the BES.Comment 2: Please proceed expeditiously with these revisions and convey such urgency to the approving entities. Although the goal of this effort is to ensure these revisions are approved prior to the June 2016 effective date for newly identified elements under the BES definition, affected entities have no alternative but to expend resources and devote time to plan, prepare and begin compliance related activities well before June 2016.
IRC Standards Review Committee		There are multiple postings of the PRC-005 currently underway, each effort addressing different changes. Although we support and understand the need to adhere to the standards development process for standards projects, each one will have individual postings and ballots. This makes it cumbersome to reference and review layers of changes that may impact the other postings and can lead to confusion and unanticipated voting outcomes. The drafting teams need to explain how each proposed change to PRC-005 is not relevant or impactive on the other.
EDP Renewables North America LLC		Thank you for your time and efforts.

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. A subsequent version of PRC-004, i.e., PRC-004-3, also is under active standard development. Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-004-2.1a(X) for balloting purposes, may be filed for regulatory approval. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	July – August 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	September – October 2014
Final ballot	November 2014
BOT adoption	February 2015

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1a(X)
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
   4.1. Transmission Owner.
   4.2. Distribution Provider that owns a transmission Protection System.
   4.3. Generator Owner.
5. **(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

The only revisions made to this version of PRC-004 are revisions to Requirements R2 and R3 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.

This version is labeled PRC-004-2.1a(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-004 are in development. The 'X' designation reflects the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. Depending on the timing of approvals of other versions, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

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 Bulk-Power System, Requirement R2 and Requirement R3 reflect the threshold consistent with the revised BES definition. See paragraph 20 of FERC Order Approving Revised Definition in Docket No. RD14-2-000. The intent of Requirement R2 and Requirement R3 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

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. 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. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the Board of Trustees	

1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
TBD (balloted as 2.1a(X))	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of Requirements to BES dispersed power producing resources

Appendix 1[1]

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:

[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES.

A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. A subsequent version of PRC-004, i.e., PRC-004-3, also is under active standard development. Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-004-2.1a(X) for balloting purposes, may be filed for regulatory approval. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	July – August 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	September – October 2014
Final ballot	November 2014
BOT adoption	February 2015

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1a(X)
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

> The only revisions made to this version of PRC-004 are revisions to Requirements R2 and R3 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.
>
> This version is labeled PRC-004-2.1a(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-004 are in development. The 'X' designation reflects the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. Depending on the timing of approvals of other versions, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

4. **Applicability**
   - **4.1.** Transmission Owner.
   - **4.2.** Distribution Provider that owns a transmission Protection System.
   - **4.3.** Generator Owner.
5. **Effective Date:** The standard shall become effective on the first day after the date this 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 after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

> **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 Bulk-Power System, Requirement R2 and Requirement R3 reflect the threshold consistent with the revised BES definition. See paragraph 20 of FERC Order Approving Revised Definition in Docket No. RD14-2-000. The intent of Requirement R2 and Requirement R3 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

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

- For ~~This requirement does not apply to~~ Misoperations occurring on the protection systems of individual dispersed ~~generation~~power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected ~~or could have affected~~ an aggregate nameplate rating of less than or equal to 75 MVA of BES facilities, this requirement does not apply.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

- ~~This requirement does not apply to~~For Misoperations occurring on the protection systems of individual dispersed ~~generation~~power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected ~~or could have affected~~ an aggregate nameplate rating of less than or equal to 75 MVA of BES facilities, this requirement does not apply.

~~**R1.**~~

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. 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~~Regional Entity~~.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06

2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
TBD (balloted as 2.1a(X))	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of Requirements to BES dispersed power producing resources

Appendix 1[1]

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. The currently effective version of PRC-004, i.e., PRC-004-2.1a, also is under active standard development. Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-004-3(X) for balloting purposes, may be filed for regulatory approval. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	July – August 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	September – October 2014
Final ballot	November 2014
BOT adoption	February 2015

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 (—).”**	01/20/06

		2. Added "periods" to items where appropriate. Changed "Timeframe" to "Time Frame" in item D, 1.2.	
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	**FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).**	
TBD (balloted as 3(X))	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of Requirements to BES dispersed power producing resources

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**
2. **Number:** PRC-004-3
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.[1]

   4.2.1.3 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.

> The only revisions made to this version of PRC-004 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.
>
> This version is labeled PRC-004-3(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-004 are in development. The 'X' designation reflects the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. Depending on the timing of approvals of other versions, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

> **Rationale for Applicability:** Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. 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 Bulk-Power System, 4.2.1.3 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 4.2.1.3 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. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are not included in this standard because they are planned to be handled in the second phase of this project.

5. **Background**:

A key element for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In FERC Order No. 693, the Commission identified PRC-003-0 as a “fill-in-the-blank” standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- 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.
- 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).

- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needs more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

The SAR for this project also includes clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to independent of each other.

The proposed requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

6. Effective Dates:

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

In the Western Interconnection, the standard shall become effective on the first day of the first calendar quarter that is twenty-four months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. In the Western Interconnection, where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four months 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 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, identify whether its Protection System component(s) caused a Misoperation when: *[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.

M1. 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 2.1 and 2.2 below.: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 When a BES interrupting device is operated by a Composite Protection System, notification of the operation shall be provided to the other owner(s) of the Composite Protection System when:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and

2.1.2 The BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner 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 When a BES interrupting device is operated by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Acceptable evidence for Requirement R2, including Parts 2.1, 2.2, and 2.3 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, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. 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, Disturbance Monitoring Equipment (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 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. 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, Disturbance Monitoring Equipment (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. Acceptable evidence for Requirement R5 may include, but is not limited to, the following documentation (electronic or hardcopy format): a dated CAP or a dated 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. Acceptable evidence for Requirement R6 may include, but is not limited to, the following documentation (electronic or hard copy format): dated records that document the implementation of each CAP and the completion of actions for 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 12 calendar months.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5 for 12 calendar months following completion of each CAP, evaluation, and declaration.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for 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

Periodic Data Submittal

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 Assessment, Operations Planning	Medium	The responsible entity identified whether or not 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 or not 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 or not 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 or not 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 or not 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
R3	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 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
R4	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
R5	Operations Planning, Long-Term Planning	Medium	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. OR (See next page)	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 first identifying a cause of the Misoperation. OR (See next page)	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. OR (See next page)	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. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

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 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.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[2] 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[3]; 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."

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[4]." 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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[2] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[3] http://www.nerc.com/files/2011_RARPR_FINAL.pdf

[4] "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 remote Protection System is excluded.*

This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the entity must consider the entire Protection System associated with the BES interrupting device that operated. Additionally, the definition accounts for those Protection Systems with multiple levels of protection (e.g., redundant systems), such that if one component fails, but the overall intended performance of the composite protection is met – it would not be identified as a Misoperation under the definition.

(ADD AN EXAMPLE which includes the following terms)

INCLUDE DISCUSSION of:

Primary

Secondary

Local Backup

Communication-assisted relay, and

Breaker failure not being in the definition.

The purpose of having the definition of Composite Protection System is to promote reliability and not to penalize entities for implementing redundant protection (e.g., primary and secondary protection). A failure of the primary system when secondary system operates correctly is not a Misoperation of system A because the Composite Protection System (overall) operated correctly to protect the given Element

Example: There are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that mean the Composite Protection System did not misoperate?

> **Misoperation –** *The failure a Composite Protection System to operate as intended. 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 for which it is designed. Delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.*
> 4. ***Slow Trip – Other Than Fault*** – *A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed clearing of a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.*
>   5. ***Unnecessary Trip – During Fault*** – *An unnecessary Protection System operation for a Fault condition on another Element.*
>   6. ***Unnecessary Trip – Other Than Fault*** – *An unnecessary Protection System operation for a non-Fault condition for which it is not designed. A Protection System operation that is caused by on-site maintenance, testing, inspection, construction or commissioning activities is not a Misoperation.*

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.

Paglow: 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. The definition includes six categories which provide further differentiation and examples of what is 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 Misoperation as long as another component of the transformer's Composite Protection System operated to clear the Fault.
>
> **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 would not in and of itself be a Misoperation.

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 another component of the generator's Composite Protection System operated as intended (e.g., isolating the generator).

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 3:** A failure of a line's Composite Protection System to operate as quickly as intended for a line Fault is a Misoperation. A line to line fault in a weak portion of the system resulted in positive sequence currents below the overcurrent supervision pickup for a line current differential relay. The relay's negative sequence differential element operated instead. However, the original relay settings did not account for the additional detection time required for the negative sequence element.

Installing high-speed protection may be a part of a utility's standard practice without having the need for high-speed protection to prevent voltage or dynamic instability or to maintain relay coordination. For this case, a "Slow Trip – During Fault" of the high-speed protection is not a Misoperation because it would not negatively impact the dynamic BES performance, unless the

Composite Protection System operation is slower than previously identified as being necessary to prevent voltage or dynamic instability. The Composite Protection System must also coordinate with other Protection Systems to prevent the trip (e.g., an over-trip) of additional Protection Systems.

The phrase "slower than required" means the Composite Protection System operated slower than the objective of the owner(s). 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 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.

Slow Trip – Other Than Fault

The phrase "slower than required" means the Composite Protection System operated slower than the objective of the owner(s). 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 stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A failure of a generator's Composite Protection System to operate as quickly as intended for an overexcitation condition is a Misoperation.

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.

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.

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 6d: 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.

The “on-site” activities at one location that initiates a trip to another location are included in this exemption; however, once the maintenance, testing, inspection, construction, or commissioning is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Paglow: If the coordination error was at the remote terminal (set too fast), then it is an "Unnecessary Trip" at the remote location. If the coordination error was at the local terminal (set too slow), then it is a "Slow Trip" at the local location.

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 which occur with the protected Element out of service, 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.

The above are examples only, and do not constitute an all-inclusive list of conditions that would not be a Misoperation.

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 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.

In the examples above, the standard is not applicable to operation of the protective relay because it operated 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, says: "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 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 that its Protection System component(s) as causing the BES interrupting device operation.

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.

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 Disturbance Monitoring Equipment (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. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation until the entity determines otherwise. 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 or not a Misoperation of its Protection System component(s) occurred.

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.

Requirement R2

For Requirement R2 (i.e., 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) 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, 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 or 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.

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. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation until the entity determines otherwise. 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 latter half of the 120 calendar days allotted to the BES interrupting device owner.

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 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, the entity 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 (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 even years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. 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, or requesting a necessary outage.

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.

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: All relays at station A and B functioned properly during testing on 08/26/2014. 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: 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.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan or 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."* 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 create 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 CAPs 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 time periods within Requirement R1, R3 and Requirement R5 are distinct and separate. If a cause of a Misoperation is identified quickly, the time period in Requirement R1 or R3 ends and the 60 calendar day period to develop the CAP becomes applicable. The ultimate goal is to keep all time periods as short as possible, including the correction of the cause(s) of the Misoperation. See Requirement R6 for CAP implementation. Where there are multiple Protection System owners involved in a Misoperation, each owner whose Protection System component(s) contributed to the Misoperation is subject to Requirement R5.

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 must include an evaluation of other Protection Systems including other locations to be complete.

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

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor. 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 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. 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 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. 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 in an example of a declaration 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 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. The 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. The 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. The 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 resource rescheduling from 02/01/15 to 03/01/2015. Following the timetable change, 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).

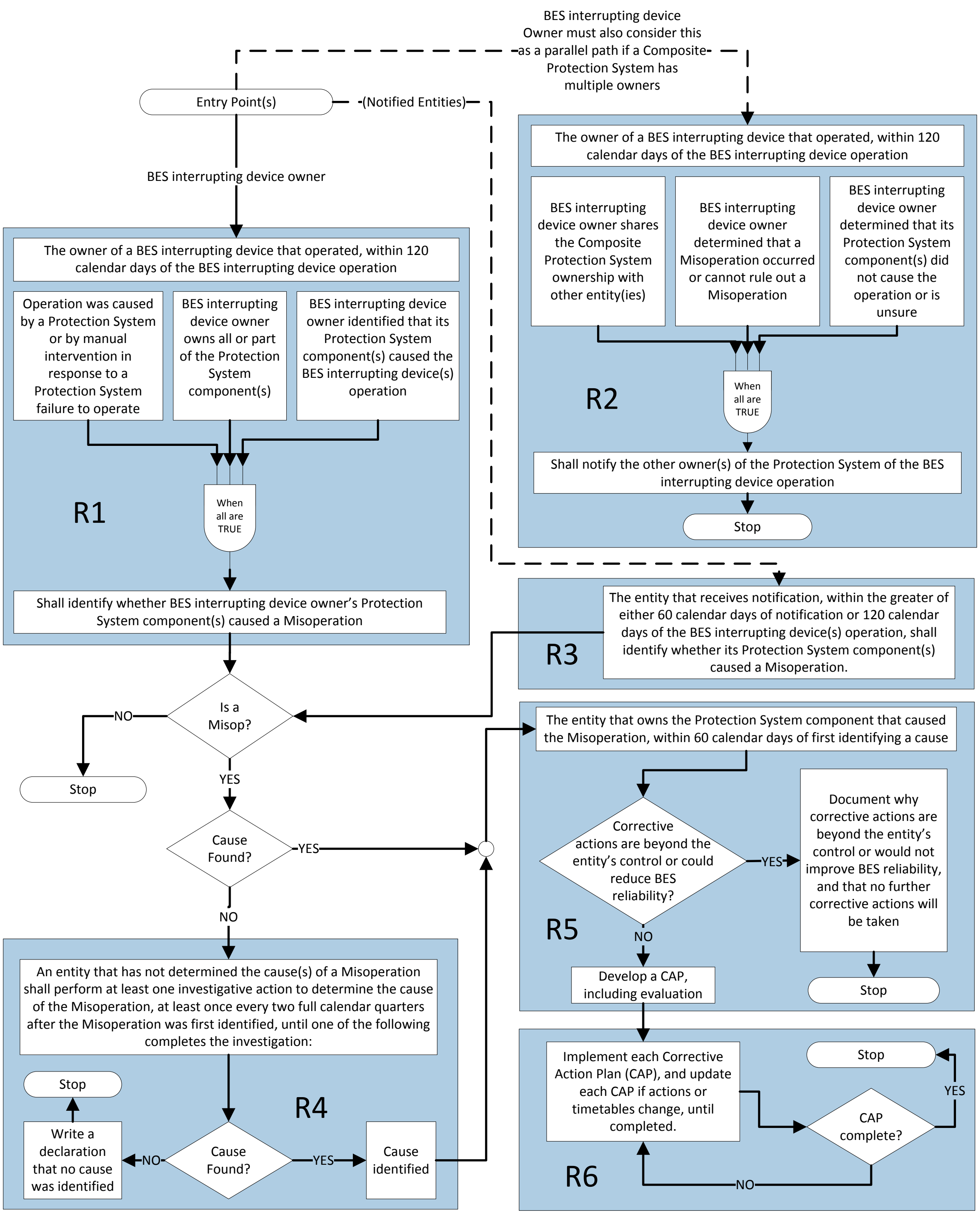
Example R6d: Actions: Fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

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 the documented actions to resolve the specific problem (i.e., Misoperation) are completed which may include those actions resulting from the entity's evaluation of other locations, if not addressed through a separate CAP.

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



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. The currently effective version of PRC-004, i.e., PRC-004-2.1a, also is under active standard development. Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-004-3(X) for balloting purposes, may be filed for regulatory approval. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	July – August 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	September – October 2014
Final ballot	November 2014
BOT adoption	February 2015

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 (—).”**	01/20/06

		2. Added "periods" to items where appropriate. Changed "Timeframe" to "Time Frame" in item D, 1.2.	
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	**FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).**	
TBD (balloted as 3(X))	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of Requirements to BES dispersed power producing resources

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**
2. **Number:** PRC-004-3
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~~ are excluded~~.

   ~~4.2.1.1~~4.2.1.2 Protective functions intended to operate as a control function during switching~~ are excluded~~.[1]

   4.2.1.3 Protection Systems of individual dispersed power producing ~~generation~~ resources identified under Inclusion I4 of the BES definition where the Misoperations affected ~~or could have 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.

> The only revisions made to this version of PRC-004 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.
>
> This version is labeled PRC-004-3(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-004 are in development. The 'X' designation reflects the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. Depending on the timing of approvals of other versions, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

Rationale for Applicability: Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. 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 Bulk-Power System, 4.2.1.3 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 4.2.1.3 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. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are not included in this standard because they are planned to be handled in the second phase of this project.

5. Background:

A key element for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- 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.

- 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).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needs more specificity and clarity. The terms “specified time” and “abnormal condition” are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

The SAR for this project also includes clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information (“data request”). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to independent of each other.

The proposed requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

6. **Effective Dates:** ~~See Implementation Plan~~

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

In the Western Interconnection, the standard shall become effective on the first day of the first calendar quarter that is twenty-four months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. In the Western Interconnection, where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four months 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 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, identify whether its Protection System component(s) caused a Misoperation when: *[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.

M1. 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 2.1 and 2.2 below.~~notify the other owner(s) of the Protection System of the operation when~~: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 When a BES interrupting device is operated by a Composite Protection System, notification of the operation shall be provided to the other owner(s) of the Composite Protection System when:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and

2.1.2 The BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner 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 When a BES interrupting device is operated by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Acceptable evidence for Requirement R2, including Parts 2.1, 2.2, and 2.3 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, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. 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, Disturbance Monitoring Equipment (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 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. 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, Disturbance Monitoring Equipment (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. Acceptable evidence for Requirement R5 may include, but is not limited to, the following documentation (electronic or hardcopy format): a dated CAP or a dated 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. Acceptable evidence for Requirement R6 may include, but is not limited to, the following documentation (electronic or hard copy format): dated records that document the implementation of each CAP and the completion of actions for 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 12 calendar months.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5 for 12 calendar months following completion of each CAP, evaluation, and declaration.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for 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

Periodic Data Submittal

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 Assessment, Operations Planning	Medium	The responsible entity identified whether or not 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 or not 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 or not 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 or not 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 or not 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
R3	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 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
R4	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
R5	Operations Planning, Long-Term Planning	Medium	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. OR (See next page)	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 first identifying a cause of the Misoperation. OR (See next page)	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. OR (See next page)	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. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

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 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.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[2] 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[3]; 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."

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[4]." 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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[2] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[3] http://www.nerc.com/files/2011_RARPR_FINAL.pdf

[4] "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 ~~the~~ Protection System(s) that function collectively to protect an Element~~, such as any primary, secondary, local backup, and communication-assisted relay systems~~. Backup protection provided by a remote Protection System is excluded.*

This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the entity must consider the entire Protection System associated with the BES interrupting device that operated. Additionally, the definition accounts for those Protection Systems with multiple levels of protection (e.g., redundant systems), such that if one component fails, but the overall intended performance of the composite protection is met – it would not be identified as a Misoperation under the definition.

(ADD AN EXAMPLE which includes the following terms)

INCLUDE DISCUSSION of:

Primary

Secondary

Local Backup

Communication-assisted relay, and

Breaker failure not being in the definition.

The purpose of having the definition of Composite Protection System is to promote reliability and not to penalize entities for implementing redundant protection (e.g., primary and secondary protection). A failure of the primary system when secondary system operates correctly is not a Misoperation of system A because the Composite Protection System (overall) operated correctly to protect the given Element

Example: There are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that mean the Composite Protection System did not misoperate?

Misoperation – *The failure a Composite Protection System to operate as intended. 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 for which it is designed. Delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.*
4. ***Slow Trip – Other Than Fault –*** *A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed clearing of a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.*
    5. ***Unnecessary Trip – During Fault –*** *An unnecessary Protection System operation for a Fault condition on another Element.*
    6. ***Unnecessary Trip – Other Than Fault –*** *An unnecessary Protection System operation for a non-Fault condition for which it is not designed. A Protection System operation that is caused by on-site maintenance, testing, inspection, construction or commissioning activities is not a Misoperation.*

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.

Paglow: 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. The definition includes six categories which provide further differentiation and examples of what is 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 Misoperation as long as another component of the transformer's Composite Protection System operated to clear the Fault.
>
> **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 would not in and of itself be a Misoperation.

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 another component of the generator's Composite Protection System operated as intended (e.g., isolating the generator).

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 3:** A failure of a line's Composite Protection System to operate as quickly as intended for a line Fault is a Misoperation. A line to line fault in a weak portion of the system resulted in positive sequence currents below the overcurrent supervision pickup for a line current differential relay. The relay's negative sequence differential element operated instead. However, the original relay settings did not account for the additional detection time required for the negative sequence element.

Installing high-speed protection may be a part of a utility's standard practice without having the need for high-speed protection to prevent voltage or dynamic instability or to maintain relay coordination. For this case, a "Slow Trip – During Fault" of the high-speed protection is not a Misoperation because it would not negatively impact the dynamic BES performance, unless the Composite Protection System operation is slower than previously identified as being necessary to prevent voltage or dynamic instability. The Composite Protection System must also coordinate with other Protection Systems to prevent the trip (e.g., an over-trip) of additional Protection Systems.

The phrase "slower than required" means the Composite Protection System operated slower than the objective of the owner(s). 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 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.

Slow Trip – Other Than Fault

The phrase "slower than required" means the Composite Protection System operated slower than the objective of the owner(s). 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 stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A failure of a generator's Composite Protection System to operate as quickly as intended for an overexcitation condition is a Misoperation. ~~This category of Misoperation could result in equipment damage.~~

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.

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.

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 6d: 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.

The "on-site" activities at one location that initiates a trip to another location are included in this exemption; however, once the maintenance, testing, inspection, construction, or commissioning is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Paglow: If the coordination error was at the remote terminal (set too fast), then it is an "Unnecessary Trip" at the remote location. If the coordination error was at the local terminal (set too slow), then it is a "Slow Trip" at the local location.

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 which occur with the protected Element out of service, 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.

The above are examples only, and do not constitute an all-inclusive list of conditions that would not be a Misoperation.

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.

In the examples above, the standard is not applicable to operation of the protective relay because it operated 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.~~In the example above, the standard is not applicable; however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when~~

~~intended to provide generator anti-motoring protection. For example, reverse power relays are typically installed as the primary protection for a generating unit to guard against motoring. Though, operators often take advantage of this functionality and use the Protection System's reverse power protective function as a normal procedure to shutdown a generating unit.~~

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, says: "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 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 that its Protection System component(s) as causing the BES interrupting device operation.

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.

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 Disturbance Monitoring Equipment (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. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation until the entity determines otherwise. 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 or not a Misoperation of its Protection System component(s) occurred.

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.

Requirement R2

For Requirement R2 (i.e., 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) 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, 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 or 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.

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. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation until the entity determines otherwise. 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 latter half of the 120 calendar days allotted to the BES interrupting device owner.

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 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, the entity 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 (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 even years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. 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, or requesting a necessary outage.

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.

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**: All relays at station A and B functioned properly during testing on 08/26/2014. 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:** 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.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan or 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."* 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 create 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 CAPs 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 time periods within Requirement R1, R3 and Requirement R5 are distinct and separate. If a cause of a Misoperation is identified quickly, the time period in Requirement R1 or R3 ends and the 60 calendar day period to develop the CAP becomes applicable. The ultimate goal is to keep all time periods as short as possible, including the correction of the cause(s) of the Misoperation. See Requirement R6 for CAP implementation. Where there are multiple Protection System owners involved in a Misoperation, each owner whose Protection System component(s) contributed to the Misoperation is subject to Requirement R5.

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 must include an evaluation of other Protection Systems including other locations to be complete.

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

Example R5a: Actions: Remove the relay from service. Replace capacitor. 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 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. 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 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. 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 in an example of a declaration 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 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. The 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. The 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. The 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 resource rescheduling from 02/01/15 to 03/01/2015. Following the timetable change, 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).

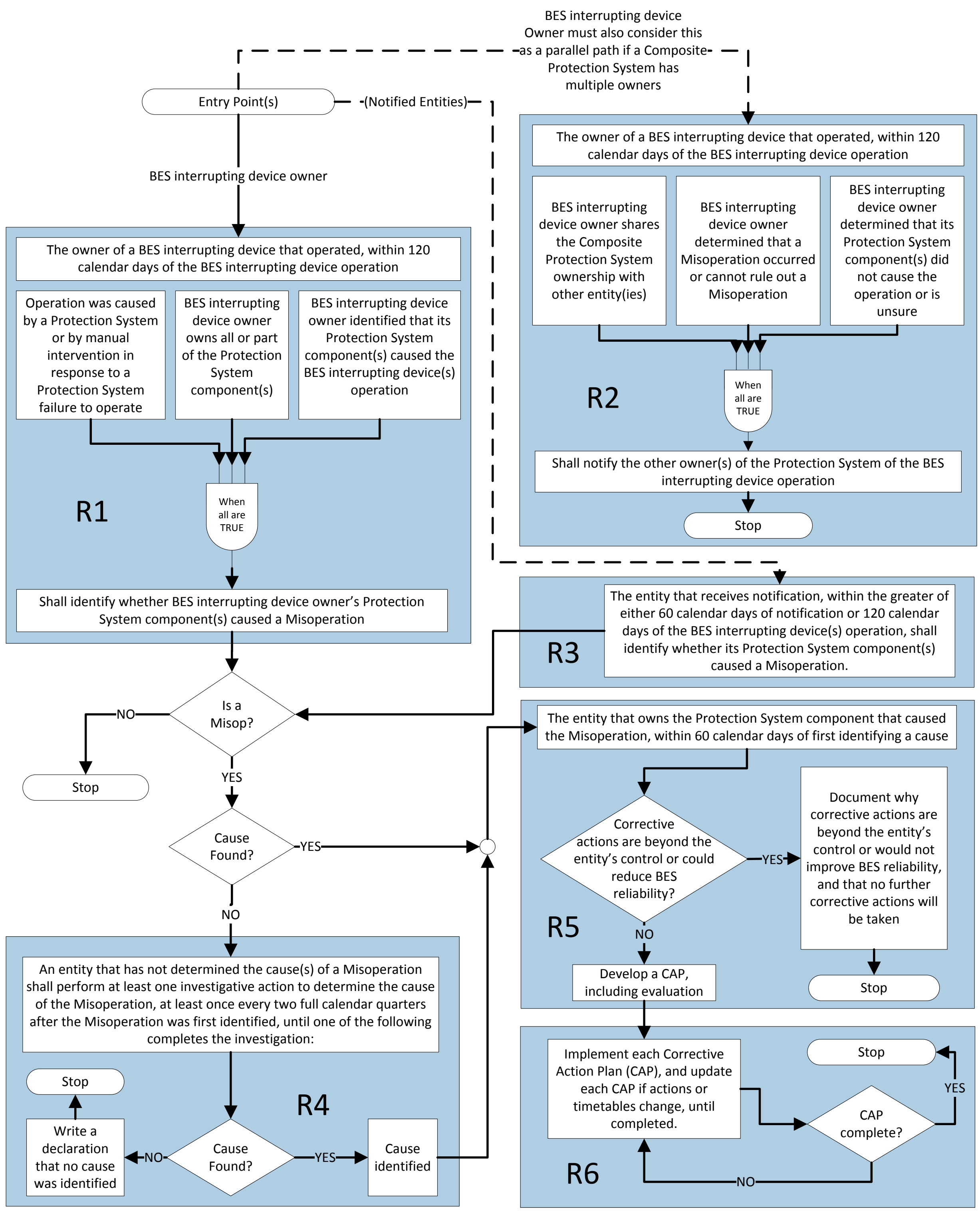
Example R6d: Actions: Fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

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 the documented actions to resolve the specific problem (i.e., Misoperation) are completed which may include those actions resulting from the entity's evaluation of other locations, if not addressed through a separate CAP.

Process Flow Chart: Below is a graphical representation ~~of the expected process created by the standard, including~~demonstrating the relationships between requirements:



Implementation Plan

Dispersed Generation Resources
PRC-004-2.1a(X)

The standard version number currently include an (X) to indicate the version numbering will be updated. PRC-004 is being substantively revised in Project 2010-05.1 concurrently with the revisions to address applicability to dispersed generation resources in this project. Depending on the timing of respective approvals in each project, NERC will assign the appropriate version number prior to BOT adoption.

Standards Involved
Approval:

- PRC-004-2.1a(X) – Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-2.1a – Protection System Misoperation Identification and Correction

Prerequisite Approvals:
N/A

Background
In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk-Power System.

General Considerations
PRC-004-2.1a(X) is proposed for approval to align the applicability section of PRC-004-2.1a with the revised definition of "Bulk Electric System." Given the timing of concurrent standards development of PRC projects, PRC-004-2.1a may already be retired pursuant to an Implementation Plan of a successor version of PRC-004 by the time the revised definition of "Bulk Electric System" becomes effective. If this occurs, PRC-004-2.1a(X) will not go into effect.

Effective Date
PRC-004-2.1a(X) shall become effective immediately after 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.

Retirement of Existing Standards:

The existing standard, PRC-004-2.1a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-2.1a(X).

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider
- Balancing Authority

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Implementation Plan

Dispersed Generation Resources

PRC-004-3(X)

The standard version number currently include an (X) to indicate the version numbering will be updated. PRC-004 is being substantively revised in Project 2010-05.1 concurrently with the revisions to address applicability to dispersed generation resources in this project. Depending on the timing of respective approvals in each project, NERC will assign the appropriate version number prior to BOT adoption.

Standards Involved

Approval:

- PRC-004-3(X) – Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-3 – Protection System Misoperation Identification and Correction

Prerequisite Approvals:

- PRC-004-3 – Protection System Misoperation Identification and Correction

Background

In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk-Power System.

General Considerations

PRC-004-3(X) is proposed for approval to align the applicability section of PRC-004-3 with the revised definition of "Bulk Electric System." The intent of the Standard Drafting Team was to allow for flexibility of the PRC-004 applicability section regardless of the version that is currently in effect when an applicable governmental authority acts on the PRC-004-3(X) filing. Currently, PRC-004-2.1a is in effect as PRC-004-3 is currently being developed in Project 2010-05.1. Depending on the timing of approvals for various versions of PRC-004, PRC-004-2.1a may still be in effect at the time the revised definition of "Bulk Electric System" becomes effective. If this occurs, PRC-004-2.1a(X) will go into effect and PRC-004-3(X) shall go into effect once the technical revisions developed in Project 2010-05.1 are approved by applicable regulators, or as otherwise provided for in jurisdictions that do not require regulatory approvals.

Effective Date

PRC-004-3(X) shall become effective immediately after 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.

Retirement of Existing Standards:

The existing standard, PRC-004-3, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-3(X).

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider
- Balancing Authority

Unofficial Comment Form

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standards. The electronic comment form must be completed by **August 25, 2014**.

If you have questions please contact Sean Cavote or by telephone at 404.446.9697.

All documents for this project are available on the project page.

Background Information

This posting solicits formal comments on one of three Project 2014-01 Dispersed Generation Resources (DGR) "high-priority" Reliability Standards as identified in the draft white paper (White Paper) prepared by the Project 2014-01 (Project) drafting team (DGR SDT).

The goal of the Project is to ensure that the Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System, as the characteristics of operating dispersed power producing resources can be unique. In light of the revised Bulk Electric System (BES) definition approved by the Federal Energy Regulatory Commission in 2014, the intent of this Project is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources where the status quo does not create a reliability gap.

The DGR SDT performed a review of all standards that apply to GOs and GOPs and categorized how each standard should be applied to dispersed power producing resources to accomplish the reliability purpose of the standard. The DGR SDT developed the White Paper to explain its approach, which was posted on April 17, 2014 for an informal comment period.[1] The industry feedback received on the White Paper allowed the DGR SDT to refine its approach and finalize recommended revisions to the standards. As part of this review the DGR SDT determined that there are three high-priority standards in which immediate attention is required to provide direction to industry stakeholders as soon as feasible regarding how to appropriately direct compliance related preparations:

- PRC-004-2.1a;
- PRC-005; and
- VAR-002.[2]

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[1] The current version of the White Paper can be downloaded on the Project web page at http://www.nerc.com/pa/Stand/Pages/Project-2014-01-Standards-Applicability-for-Dispersed-Generation-Resources.aspx.
[2] Relevant versions of PRC-005 (PRC-005-2(X), PRC-005-3(X), and PRC-005-X(X)) and VAR-002 (VAR-002-2b(X) and VAR-002-4) were posted for a 45-day comment period on June 12, 2014.

Because each of the “high-priority” standards has recently been revised or is undergoing revision in another current project, the DGR SDT has developed revisions to multiple versions of each standard to allow for different possibilities in the timing of regulatory approvals. When the revisions are being applied to a version that is not the last approved version of the standard or to a version that is pending regulatory approval, the version is noted with “(X)” after it. For example, this posting includes PRC-004-2.1a(X), which proposes applicability changes to PRC-004-2.1a, as well as PRC-004-3(X), which proposes applicability changes to PRC-004-3.[3] Please note that any versions of the standards posted under this project with an “X” suffix will have a version number applied at a later time in order to manage sequencing of version numbers. The intent of balloting the recommended applicability revisions separately from the technical changes that are ongoing in other projects is to provide flexibility to allow approved applicability revisions to move forward on an expedited timeline as needed to support implementation of the revised definition of BES.

The DGR SDT responded to industry comments as contained in its Consideration of Comments, which is posted on the project page, along with the DGR SDT’s response to comments on the original Standards Authorization Request (SAR) that defines the scope of this Project.

The DGR SDT continues to coordinate with other NERC Reliability Standards projects currently under development to ensure continuity and to develop a posting strategy that ensures all applicability changes approved by ballot are filed and implemented as quickly as possible without adversely impacting other projects. The DGR SDT Coordination Plan posted on the project page details that coordination.

Summary of Proposed Changes

The DGR’s recommended changes are limited to revising the applicability of the relevant versions of PRC-004 to ensure that the requirements of the standard are applied appropriately for dispersed power producing resources included in the Bulk Electric System through Inclusion I4 of the definition of Bulk Electric System. Although the redlined versions of the standard included with this posting contain changes that appear structurally different, the substance of the changes in each respective set of standards is the same.

The drafting team has posted the following standards, along with corresponding implementation plans:

- PRC-004-2.1a(X) (clean and redlined against PRC-004-2.1a)
- PRC-004-3(X) (clean and redlined against PRC-004-3)

Please note that the DGR SDT has not revised the Violation Risk Factors (VRFs) or Violation Severity Levels (VSLs) associated with the subject standards because the proposed revisions do not change the reliability intent or impact of any of the requirements. If the applicability recommendations are approved by

[3] PRC-004-2.1a is the currently effective version of the standard, while PRC-004-3 is in active standard development in Project 2010-05.1 Protection System (Misoperations). PRC-004-3 also was posted for a 45-day formal comment period from May 16, 2014 through June 30, 2014.

industry, the DGR SDT's intent is that the VRFs and VSLs for each requirement would be unchanged from those either previously approved (for currently enforceable versions of standards or those pending regulatory approval) or would be developed by the drafting team responsible for revising technical content (for those versions of standards currently in development in another standards project).

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you agree with the revisions made in proposed PRC-004-2.1a(X) to clarify applicability of PRC-004-2.1a to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

2. Do you agree with the revisions made in proposed PRC-004-3(X) to clarify applicability of PRC-004-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

3. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

   Yes:

   No:

   Comments:

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Project 2014-01 Dispersed Generation Resources

DRAFT Plan for Standards Drafting Team (SDT) Coordination and Balloting Multiple Versions of Standards | June 12, 2014

Background

Pursuant to the Standards Authorization Request for this project posted on November 20, 2014, the Project 2014-01 Dispersed Generation Resources (DGR) SDT proposes to modify PRC-004-2.1a, PRC-004-3, PRC-005-2, PRC-005-3, PRC-005-X, VAR-002-2b, and VAR-002-3 to account for the unique characteristics of dispersed power producing resources. As the DGR SDT has explained in the White Paper it has developed, the DGR SDT has classified each of these standards as high-priority standards requiring applicability changes as soon as practicable.

Because each of the high-priority standards has recently been revised or is undergoing revision in another active standard development project, the DGR SDT has developed revisions to multiple versions of each standard to allow for different possibilities in the timing of regulatory approvals. Specifically, two of the three standards identified by the DGR SDT as high priority (PRC-004 and PRC-005) are being revised by other projects. NERC and the DGR SDT recognize that developing multiple versions of the same standard in different projects may be confusing; however, developing and balloting the recommended DGR applicability revisions separately from the technical changes that are ongoing in other active standard development projects provides flexibility in effectuating applicability revisions on an expedited timeline as needed to support implementation of the revised definition of the Bulk Electric System. The DGR project is being carefully coordinated with other active standard development projects with careful consideration of the period of time various versions of each standard may be in effect.

When DGR revisions are applied to a standard version that is not the last approved version of the standard or to a standard version that may be superseded by another version in active standard development outside the DGR project, the version is noted with "(X)" after it. For example, the DGR SDT is developing PRC-005-2(X), which proposes applicability changes to PRC-005-2, as well as PRC-005-3(X), which proposes applicability changes to PRC-005-3. Please note that NERC will apply at a later time the appropriate version numbers to standard versions containing an "X" suffix in order to effectively manage sequencing of version numbers in these projects.

PRC-004 DGR Applicability Modifications

(*Note that since PRC-004-3 is posted for a 45-day comment period and additional ballot through June 30, 2014, NERC is deferring posting DGR applicability recommendations on PRC-004 until after that ballot closes.)*

PRC-004-2.1a (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) is FERC-approved and has been enforceable since November 25, 2013. PRC-004-3 is in active standard development in Project 2010-05.1 and may supersede PRC-004-2.1a; however, until PRC-004-3 is completed, approved by applicable government authorities, and becomes enforceable, there may be a need for revisions to tailor the applicability of PRC-004-2.1a, which the DGR SDT intends to ballot as PRC-004-2.1a(X). The proposed implementation period for PRC-004-3 is 12 months.

PRC-004-3 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) is currently in active standard development in Project 2010-05.1 Protection System Misoperations. The DGR SDT and the Protection System Misoperations SDT are coordinating regarding changes to the applicability of PRC-004. The DGR

SDT intends to ballot proposed applicability revisions to PRC-004-3 as PRC-004-3(X). Depending on the timing of completion of Project 2010-05.1 relative to Project 2014-01, both PRC-004-2.1a(X) and PRC-004-3(X) may be needed.

PRC-005 DGR Applicability Modifications

PRC-005-2 (Protection System Maintenance): PRC-005-2 is FERC-approved and will become enforceable on April 1, 2015. PRC-005-2 has a 12-year phased-in implementation period and may be enforceable for a period of time before PRC-005-3 becomes enforceable after approval by the applicable government authorities. Therefore, the DGR SDT is balloting proposed revisions to the applicability of PRC-005-2 as PRC-005-2(X).

PRC-005-3 (Protection System and Automatic Reclosing Maintenance): PRC-005-3 was adopted by the NERC Board of Trustees (Board) on November 7, 2013 and filed with the applicable governmental authorities on February 14, 2014. Upon regulatory approval, PRC-005-3 will supersede PRC-005-2, and according to its proposed implementation plan, will continue the 12-year implementation period for components included in PRC-005-2. Therefore, the DGR SDT is balloting proposed revisions to the applicability of PRC-005-3 as PRC-005-3(X).

PRC-005-X (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance): PRC-005-X is currently in an active standards development project. A ballot for PRC-005-X concluded on June 3, 2014 but did not receive sufficient affirmative votes for approval. The PRC-005-X SDT will consider comments and, if needed, make revisions to the standard. Language to clarify the applicability of the requirements of PRC-005-X was agreed to by both SDTs, and is being balloted in the DGR project as PRC-005-X(X). Depending on the timing of the completion of the DGR project relative to Project 2007-17.3, NERC will determine the appropriate approach to filing applicability changes approved by balloters and adopted by the Board.

VAR-002 DGR Applicability Modifications

VAR-002-2b (Generator Operation for Maintaining Network Voltage Schedules) is FERC-approved and has been enforceable since July 1, 2013. A successor version, VAR-002-3, is pending regulatory approval and has a proposed implementation period of one quarter. Depending on the time of regulatory approvals of VAR-002-3, VAR-002-2b may remain in effect. Therefore, the DGR SDT is balloting proposed revisions to clarify the applicability of VAR-002-2b as VAR-002-2b(X).

VAR-002-3 (Generator Operation for Maintaining Network Voltage Schedules) was adopted by the Board on May 7, 2014 and filed with the applicable governmental authorities on June 10, 2014. No other version of VAR-002 is in active standard development outside the DGR project. Therefore, the DGR SDT is balloting proposed revisions to VAR-002-3 as VAR-002-4.

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation		
Date Submitted:	10/1/2013		
SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
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. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard. **PRC-005-2** Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply. **FAC-008-3** For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information
Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels. **PRC-023-3/PRC-025-1** In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements. **PRC-004-2** There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above. **VAR-002-2** Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard. **General review of IROs, MODs, PRCs, TOPs** IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

Reliability Functions		
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-004-2.1a(X) and PRC-004-3(X)

Initial Ballots Now Open through August 25, 2014

Now Available

Initial ballots for two **Project 2014-01 Dispersed Generation Resources "high-priority" Reliability Standards, (PRC-004-2.1a(X) and PRC-004-3(X))** as identified in the draft white paper prepared by the Project 2014-01 drafting team are open through **8 p.m. Eastern on Monday, August 25, 2014.**

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standards by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Formal Comment Period Now Open through August 25, 2014
Ballot Pools Forming Now through July 16, 2014

Now Available

A 45-day posting to solicit formal comments on two Project 2014-01 Dispersed Generation Resources "high-priority" Reliability Standards, (PRC-004-2.1a(X) and PRC-004-3(X)) as identified in the draft white paper prepared by the Project 2014-01 drafting team is open through **8 p.m. Eastern on Monday, August 25, 2014.**

If you have questions please contact Sean Cavote (via email) or by telephone at (404) 446-9697.

Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments on the standards and implementation plans. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Instructions for Joining Ballot Pools

Ballot pools are currently being formed. Registered Ballot Body members must join the ballot pools to be eligible to cast ballots. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

Please note: As a convenience to stakeholders, if you have previously joined the ballot pool for VAR-002-2b(X), no action is needed - you have automatically been entered into both the PRC-004-2.1a(X) and PRC-004-3(X) ballot pools. If you have been automatically entered and do not wish to participate, please contact Wendy Muller prior to the July 16, 2014 to have your name removed.

The following ballot pool join periods have been extended to 8 p.m. Eastern on Wednesday, July 16, 2014 in order to keep the closing dates for Project 2014-01 the same:

PRC-005-2(X)
PRC-005-3(X)
PRC-005-x(X)

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RELIABILITY CORPORATION

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Formal Comment Period Now Open through August 25, 2014
Ballot Pools Forming Now through July 16, 2014

Now Available

A 45-day posting to solicit formal comments on two Project 2014-01 Dispersed Generation Resources "high-priority" Reliability Standards, (PRC-004-2.1a(X) and PRC-004-3(X)) as identified in the draft white paper prepared by the Project 2014-01 drafting team is open through **8 p.m. Eastern on Monday, August 25, 2014.**

If you have questions please contact Sean Cavote (via email) or by telephone at (404) 446-9697.

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Please note: As a convenience to stakeholders, if you have previously joined the ballot pool for VAR-002-2b(X), no action is needed - you have automatically been entered into both the PRC-004-2.1a(X) and PRC-004-3(X) ballot pools. If you have been automatically entered and do not wish to participate, please contact Wendy Muller prior to the July 16, 2014 to have your name removed.

The following ballot pool join periods have been extended to 8 p.m. Eastern on Wednesday, July 16, 2014 in order to keep the closing dates for Project 2014-01 the same:

PRC-005-2(X)
PRC-005-3(X)
PRC-005-x(X)

VAR-002-2b(X)
VAR-002-4

During the pre-ballot window, members of the ballot pools may communicate with one another by using their "ballot pool list servers." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

bp-2014-01__PRC-004-3_X_in@nerc.com

bp-PRC-004-2.1a_X_SDTS_in@nerc.com

Next Steps
A ballot period for the standards will be conducted **August 15-25, 2014.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

VAR-002-2b(X)
VAR-002-4

During the pre-ballot window, members of the ballot pools may communicate with one another by using their "ballot pool list servers." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

bp-2014-01__PRC-004-3_X_in@nerc.com

bp-PRC-004-2.1a_X_SDTS_in@nerc.com

Next Steps

A ballot period for the standards will be conducted **August 15-25, 2014.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
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Standards Announcement

Project 2014-01 Applicability for Dispersed Resources Standards
PRC-004-2.1a(X) and PRC-004-3(X)

Initial Ballot Results

Now Available

Initial ballots for **Project 2014-01 Dispersed Generation Resources Reliability Standards, PRC-004-2.1a(X) and PRC-004-3(X)** concluded at **8 p.m. Eastern on Tuesday, August 26, 2014**.

The standards achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

	Ballot Results
	Quorum /Approval
PRC-004-2.1a(X)	81.79% / 92.09%
PRC-004-3(X)	81.75% / 87.45%

Background information for this project can be found on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-004-2.1a(X)
Ballot Period:	8/15/2014 - 8/26/2014
Ballot Type:	Initial
Total # Votes:	319
Total Ballot Pool:	390
Quorum:	81.79 % The Quorum has been reached
Weighted Segment Vote:	92.09 %
Ballot Results:	The ballot has closed

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	63	0.926	5	0.074	0	14	23
2 - Segment 2	8	0.4	3	0.3	1	0.1	0	3	1
3 - Segment 3	85	1	55	0.902	6	0.098	1	14	9
4 - Segment 4	29	1	16	0.941	1	0.059	0	7	5
5 - Segment 5	92	1	52	0.929	4	0.071	0	15	21
6 - Segment 6	54	1	34	0.872	5	0.128	0	6	9
7 - Segment 7	3	0.1	1	0.1	0	0	0	0	2
8 - Segment 8	4	0.4	4	0.4	0	0	0	0	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	8	0.7	7	0.7	0	0	0	1	0
Totals	**390**	**6.7**	**236**	**6.17**	**22**	**0.53**	**1**	**60**	**71**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
1	Hydro-Quebec TransEnergie	Martin Boisvert		
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS

				- (Public Service Enterprise Group)
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Abstain	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle		
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support Public Service Enterprise Group ("PSEG") comments)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS comments)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		

1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
3	Colorado Springs Utilities	Jean Mueller	Abstain	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC - RSC)
3	JEA	Garry Baker	Negative	NO COMMENT RECEIVED -

				(JEA)
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble		

4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cowlitz PUD - Russ Noble)
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren comments)
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Abstain	
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Abstain	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cowlitz PUD)
5	Dairyland Power Coop.	Tommy Drea		

5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Terra-Gen Power	Jessie Nevarez		
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		

5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra	Abstain	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	

6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS comments)
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-01_ PRC-004-3(X)
Ballot Period:	8/15/2014 - 8/26/2014
Ballot Type:	Initial
Total # Votes:	318
Total Ballot Pool:	389
Quorum:	81.75 % The Quorum has been reached
Weighted Segment Vote:	87.45 %
Ballot Results:	The ballot has closed

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	104	1	59	0.881	8	0.119	0	15	22
2 - Segment 2	8	0.4	3	0.3	1	0.1	0	3	1
3 - Segment 3	85	1	54	0.885	7	0.115	1	13	10
4 - Segment 4	29	1	13	0.765	4	0.235	0	7	5
5 - Segment 5	92	1	49	0.907	5	0.093	0	17	21
6 - Segment 6	54	1	32	0.821	7	0.179	0	6	9
7 - Segment 7	3	0.1	1	0.1	0	0	0	0	2
8 - Segment 8	4	0.4	4	0.4	0	0	0	0	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	8	0.7	7	0.7	0	0	0	1	0
Totals	**389**	**6.7**	**223**	**5.859**	**32**	**0.841**	**1**	**62**	**71**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
1	Hydro-Quebec TransEnergie	Martin Boisvert		
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public

				Service Enterprise Group)
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Abstain	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle		
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support Public Service Enterprise Group ("PSEG") comments)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS comments)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Marc Donaldson)

1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
3	Colorado Springs Utilities	Jean Mueller		
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC - RSC)
3	JEA	Garry Baker	Negative	NO COMMENT RECEIVED - (JEA)
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	

3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	COMMENT RECEIVED
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Cowlitz PUD - Russ Noble)
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by Seminole Electric Cooperative Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Marc Donaldson)
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren's comments)
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Abstain	
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Abstain	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
				SUPPORTS

5	Cowlitz County PUD	Bob Essex	Negative	THIRD PARTY COMMENTS - (Cowlitz PUD)
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Marc Donaldson)
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Terra-Gen Power	Jessie Nevarez		
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra	Abstain	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		

6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted on behalf of Seminole Electric Cooperative by its Corporate Compliance department)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS comments)
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Marc Donaldson)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Individual or group. (29 Responses)
Name (15 Responses)
Organization (15 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (3 Responses)
Comments (29 Responses)
Question 1 (26 Responses)
Question 1 Comments (26 Responses)
Question 2 (25 Responses)
Question 2 Comments (26 Responses)
Question 3 (0 Responses)
Question 3 Comments (26 Responses)

Individual
Brett Holland
Kansas City Power and Light
Yes
Yes
Page 21 Example: There are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that this means the Composite Protection System did not misoperate?. Also recommend deleting Paglow: in various locations.
N/A
Group
Duke Energy
Michael Lowman
Yes
Yes
Duke Energy would like to take this opportunity to thank the SDT for considering and implementing the recommendations we made. We believe these recommendations adequately address our initial concerns.
Group
Colorado Springs Utilities
Kaleb Brimhall
Agree
Public Service Enterprise Group (PSEG)
Individual
Joshua Andersen
Salt River Project
Yes

Yes
Individual
Richard Vine
California ISO
Agree
ISO/RTO Council Standards Review Committee
Group
Northeast Power Coordinating Council
Guy Zito
Yes
The definition of the BES will lead to additional costs imposed on renewable generation that could inhibit the development of these resources. In New England in particular, states have enacted aggressive renewable energy polices and are actively working to implement them cost-effectively. The SDT's efforts recognize the unique design and operating characteristics of dispersed generation resources such as wind and solar facilities. At the same time, as expressed in the SDT's April 14, 2014 Draft White Paper, any revisions are intended to ensure that they do not "create a reliability gap." These are critical considerations. The SDT is appropriately evaluating how the obligations imposed on these asset owners and operators translate to reliability benefits, which is consistent with larger efforts within NERC to incorporate cost-effectiveness analyses into the standards development process. As is the case with all standards, the revisions here would be subject to ongoing evaluation of further changes in light of experience and, in this case, the likely increased integration of dispersed power resources. The initiation of this project is beneficial to industry and this SDT's advancement of the objectives set forth in the Draft White Paper. To provide the owners and operators of dispersed generation resources (and potential future developers) with an expectation of their compliance obligations and associated costs, this effort should move forward as expeditiously as possible.
No
Refer to the response to Question 1. In addition, the redlined standard posted on the project page is the redlined Draft 4: January 17, 2014 of PRC-004-3 (Project 2010-5.1). There have been two drafts of PRC-004-3 after that and the latest Draft 6 has passed its final ballot. The Rationale Box for the Introduction (the Rationale Box does not have a title) states that the only revisions to this posting are to Section 4.2 Facilities, yet there are revisions indicated throughout the entirety of the posted standard. There are some important changes that have been approved in Draft 6 that are missing in the redlined version posted for Project 2014-01. Suggest taking the clean version of the final ballot passed PRC-004-3 and redline the Applicability Section changes only for entities to have a clear picture of what the standard is going to be. You cannot have two different versions of the same standard being balloted under different projects. The similar comment applies to the posted PRC-004-2.1a(X). The untitled Rationale Box for the Introduction states that the only revisions are to R2 and R3, yet there is redlining throughout the standard.
Regarding RC-004-3 (x): • M2; since the subparts have been updated, 2.3 needs to be removed in M2. • Guidelines and Technical Basis section-Definitions; Protection System Definition - 4th bullet should be revised to remove the word "station" from within the parentheses to be consistent with the currently approved definition of Protection System in the Glossary of Terms Used in NERC Reliability Standards. In the PRC-004-3 (X) Implementation Plan, under the effective date section, there is no mention of the differences/exceptions listed in this standard for the Western Interconnection effective dates. This should be updated. PRC-004-2.1a(X) and PRC-004-3 (X) Rationale for Applicability – The sentence that says "Misoperations occurring on the Protection Systems of individual generation…", is misleading because by definition (I4), the individual resources are BES, therefore misoperations occurring on the Protection Systems of individual resources would have an impact on BES reliability, while noting that "material impact" is not defined. In PRC-005-2(X), suggest adding the term "non-dispersed" to the wording of Part 4.2.5 to read "Protection Systems for the following non-dispersed BES generator facilities . . . ." The same suggestion for

PRC-005-3(X). There is confusion surrounding the concurrent development of PRC-004-2.1a(X) and PRC-004-3(X). Is the intent to have both these versions merged into one? If so, that should be made clear. If not, then the numbering for one or the other should be changed. The NERC Standards Numbering System stipulates that the “one-digit numeral identifying the version of that standard” is the last number in the standards number. PRC-004-2.1a(X) and PRC-004-3(X) deal with different topics.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Individual
Anthony Jablonski
ReliabilityFirst
Yes
ReliabilityFirst votes in the affirmative because we believe the changes adequately address the concerns involving individual dispersed generation power producing resources. ReliabilityFirst provides the following comments for consideration: 1. The term “protection system” is used in the newly added language but ReliabilityFirst believes this term should be capitalized since it is a NERC Defined Term (i.e., “Protection System”).
Individual
Maryclaire Yatsko
Seminole Electric Cooperative, Inc.
Yes
No
Seminole agrees with the specific revisions concerning only the changes to distributed generation, however, Seminole does not agree with the ongoing revisions through Project 2010-05.1 that are included in this revision, such as the owner of the BES interrupting device being required to initiate review in all scenarios as opposed to the entity that initiated the interrupting device’s action. Therefore, Seminole must vote negative as this revision includes language from Project 2010-05.1 that Seminole does not find agreeable.
Individual
Russell A. Noble
Public Utility District No. 1 of Cowlitz County, WA
Yes
Cowlitz PUD agrees with the outcome, but disagrees with the format. Please refer to the last question.
Yes
Cowlitz PUD agrees with the outcome, but disagrees with the format. Please refer to the last question.

Cowlitz PUD disagrees with the placement of applicability statements within the Requirement. Such statements generally should be placed in Section 4 of the Standard unless some overriding clarity issue can be identified. After review of the proposed reasons for the Standard revision, no discussion was found to explain why applicability statements were inserted into Requirements R2 and R3 rather than in Section 4. This commenter looked at the possible clarity issue at hand, but can't find justification for this construct. Inserting the following statements in Section 4 would more effectively communicate the applicability of distributed generation: "4.3.1 Those Protection Systems designed to protect BES distributed generation or associated collection systems regardless of voltage at points where the aggregate nameplate capacity is greater than 75 MVA. 4.3.2 Those protection systems associated with BES distributed generation where the aggregate nameplate capacity is equal or less than 75 MVA is not applicable." Of note, this commenter is not clear why the BES definition must be noted in the Standard, or why parallel usage of "dispersed power producing resources" should be followed. Cowlitz PUD respectfully submits that "distributed generation" is well understood and can be used while preserving the intent and clarity of the BES definition, and placement of applicability statements in this Standard is better suited in Section 4.
Individual
Marc Donaldson
Tacoma Power
Yes
No
Proposed Applicability 4.2.1.3 may be lead to misunderstanding. If failure (or slow trip) of a Protection System of an individual dispersed power producing resource, identified under Inclusion I4 of the BES definition, affects the aggregate nameplate rating of over 75 MVA of BES Facilities, it seems like that Protection System operation would be applicable to the standard. If so, clarification may be needed in the Application Guidelines, or the Applicability may need to be reworded, to help avoid a misunderstanding in which an entity thinks that the Protection System is not applicable to the standard.
The implementation plans for PRC-004-2.1a(X) and PRC-004-3(X) do not tie the effective date of the standard revision to the effective date of the BES definition. This seems incongruent with the implementation plans for PRC-005-2(X), PRC-005-3(X), and PRC-005-X(X).
Group
Dominion
Connie Lowe
Yes
Yes
PRC-004-3 (x) • M2; since the subparts have been updated, 2.3 needs to be removed in M2. • Guidelines and Technical Basis section-Definitions; Protection System Definition - 4th bullet should be revised to remove the word "station" as this word is not in the currently approved definition of Protection System in the NERC glossary of terms. In the PRC-004-3 (X) implementation plan, under the effective date section, there is no mention of the differences/exception listed in this standard for the Western Interconnection effective dates, this should be updated. PRC-004-2.1a(X) and PRC-004-3 (X) Rationale for Applicability – The sentence that says "Misoperations occurring on the Protection Systems of individual generation…", is misleading because by definition (I4), the individual resources are BES, therefore misoperations occurring on the Protection Systems of individual resources would have an impact on BES reliability, while noting that "material impact" is not defined.
Individual
David Jendras
Ameren

Agree
Ameren agrees with and supports the SERC PCS comments for Project 2014-01 Dispersed Generation Resources - PRC-004.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
Yes
The NSRF wishes to thank the SDT for including a very well written and industry needed Application Guidelines section of the proposed Standard. This should be mandatory for reviewed Standards.
Individual
Thomas Foltz
American Electric Power
Yes
Yes
Group
SERC Protection and Controls Subcommittee
David Greene
No
Requirements 2 and 3 reference “individual” dispersed generator Protection Systems and the “‘total” aggregate which is still creating some confusion. It appears that focus is on the “total” aggregate location not individual resources. Is it correct to assume if there are multiple resource owners who each have less than 75 MVA but the multiple resources aggregate at a “utility” bus, the bus is the aggregate point and would only need to be reported if at this aggregate point the loss of the aggregate is greater than 75MVA? There is also a concern that several non dispersed generator resources that may not be required to be registered that aggregate to greater than 75 MVA will have to be reported by utilities who do not own the equipment. Wording clarification and supporting Figures may need to be revised to clarify these requirements.
No
Facilities section 4.2.1.3 references “individual” dispersed generator Protection Systems and the “‘total” aggregate which is still creating some confusion. It appears that focus is on the “total” aggregate location not individual resources. Is it correct to assume if there are multiple resource owners who each have less than 75 MVA but the multiple resources aggregate at a “utility” bus, the bus is the aggregate point and would only need to be reported if at this aggregate point the loss of the aggregate is greater than 75MVA? There is also a concern that several non-dispersed generator resources that may not be required to be registered that aggregate to greater than 75 MVA will have to be reported by utilities who do not own the equipment. Wording clarification and supporting Figures may need to be revised to clarify these requirements.
The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Jonathan Meyer
Idaho Power Co.

Yes
Yes
Group
IRC Standards Review Commitee
Greg Campoli
No
In order to clearly state that analysis of misoperations is exempted for dispersed generation within a group that meets the I4 criteria, the sub bullets under R2 and R3 should be revised to: “For Misoperations occurring on the protection systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition.”
No
The comment is the same as the one providedT above in response to question 1.
Individual
John Pearson / Matt Goldberg
ISO New England
No
: In R2 and R3, the words “or could have affected” were initially added but then they were deleted. Those words should not have been deleted. The PRC subteam had indicated to us that those words would be included. The deleted words addressed the concern we expressed during the comment period for the Dispersed Generation White Paper. Specifically, we stated that we do not agree with limiting the analysis requirement to a trip of greater than 75 MVA because that only accounts for very large occurrences that could be unusual. Smaller occurrences, however, may predict an unusual large occurrence that could impact reliability. The deleted words were in fact included in the “Standards Applicability Guidelines” that were circulated for comment but were ultimately not issued. The deleted words “or could have affected” should be added back in.
No
: In R2 and R3, the words “or could have affected” were initially added but then they were deleted. Those words should not have been deleted. The PRC subteam had indicated to us that those words would be included. The deleted words addressed the concern we expressed during the comment period for the Dispersed Generation White Paper. Specifically, we stated that we do not agree with limiting the analysis requirement to a trip of greater than 75 MVA because that only accounts for very large occurrences that could be unusual. Smaller occurrences, however, may predict an unusual large occurrence that could impact reliability. The deleted words were in fact included in the “Standards Applicability Guidelines” that were circulated for comment but were ultimately not issued. The deleted words “or could have affected” should be added back in.
Individual
John Miller
Georgia Transmission Corporation
No
R2 and R3 should be approached in 004-2.1a the same as the exclusions in 004-3. Rather than state that it is excluded at the end of the sentence, simply state it on the front end. i.e. as follows: This requirement does not apply to Misoperations occurring on the protection systems of individual dispersed generation power producing resources identified under Inclusion I4 of the BES definition

where the Misoperations affected or could have affected an aggregate nameplate rating of less than or equal to 75 MVA of BES facilities.
Yes
The statement is made at the beginning of 4.2.1 "with the following exclusions:". That makes the I4 statement much clearer than the wording in 004-2.1a.
Individual
John Seelke
Public Service Enterprise Group
No
In R2 and R3, “75MVA” should be changed to “20MVA.” This would make it comparable to I2 generators. Although the change to 20MVA would have this standard apply to non-BES assets, many standards do likewise. In fact “Protection Systems,” which are the subject of this standard, are non-BES. As written, a reliability gap would be created between I4 generators and I2 generators. The proposed change violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: “Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage.” If alternative language was proposed that required the same 75MVA threshold for I2 generators, PSEG would be fine with that. But the proposed non-comparable treatment of generators is not acceptable.
No
In 4.2.1.3, “75MVA” should be changed to “20MVA.” This would make it comparable to I2 generators. Although the change to 20MVA would have this standard apply to non-BES assets, many standards do likewise. In fact “Protection Systems,” which are the subject of this standard, are non-BES. As written, a reliability gap would be created between I4 generators and I2 generators. The proposed change violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: “Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage.” If alternative language was proposed that required the same 75MVA threshold for I2 generators, PSEG would be fine with that. But the proposed non-comparable treatment of generators is not acceptable.
Group
Southern Company: Southern Company Services, Inc; Alabama Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
Yes
Looks good - removing the speculative "could have" language is helpful.
Yes
Looks good - focusing on "Misoperations that affected > 75 MVA" is appropriate.
No.
Individual
Jason Marshall
New England States Committee on Electricity (NESCOE)
Yes
The New England States Committee on Electricity (NESCOE) appreciates the work of the Dispersed Generation Resources Standard Drafting Team (SDT) in moving forward important clarifications regarding the applicability of certain standards to dispersed power producing resources. NESCOE supports the specific revisions reflected in the identified PRC standards, as well as the general intent of this Project. In comments on the first draft of the proposed BES definition, NESCOE cautioned that the definition might lead to unnecessary costs imposed on renewable generation that could inhibit

the development of these resources. That remains a concern in New England, where states have enacted aggressive renewable energy polices and are actively working to implement them cost-effectively. The SDT’s efforts recognize the unique design and operating characteristics of dispersed generation resources such as wind and solar facilities. At the same time, as expressed in the SDT’s April 14, 2014 Draft White Paper, any revisions are intended to ensure that they do not “create a reliability gap.” These are critical considerations. The SDT is appropriately evaluating how the obligations imposed on these asset owners and operators translate to reliability benefits, which is consistent with larger efforts within NERC to incorporate cost-effectiveness analyses into the standards development process. As with all standards, the revisions here would be subject to ongoing evaluation of further changes in light of experience and, in this case, the likely increased integration of dispersed power resources. NESCOE appreciates the initiation of this project and this SDT’s advancement of the objectives set forth in the Draft White Paper. To provide the owners and operators of dispersed generation resources (and potential future developers) with an expectation of their compliance obligations and associated costs, NERC should work to move this effort forward as expeditiously as possible. Thank you for your consideration of these comments.
Yes
See comments above.
While the deadline for providing comments on proposed revisions to PRC-005 and VAR-002 under this Project 2014-01 has passed, NESCOE supports these proposed changes for the same reasons discussed above and offers the following minor suggestions for clarity: • PRC-005-2(X) – suggest adding the term “non-dispersed” to the wording of 4.2.5 to read “Protection Systems for the following non-dispersed BES generator facilities . . . .” • PRC-005-3(X) – same suggestion.
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
D 1.1 states: “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” This does not take Canadian legislation into account. The clause should refer to the definition in the NERC Rules of Procedure or in the applicable legislation in a jurisdiction governed by legislation other than the NERC Rules of Procedure.
Yes
The Effective Date sections in the implementation plan and the standard at section 6 are not consistent. The standard section distinguishes Western Interconnection as having a different Effective Date from others. The Implementation plan makes no reference to this. The standard references dates of twelve months or twenty-four months after the date the standard is adopted or as otherwise provided for in that jurisdiction but the implementation plan does not make reference to these durations. As a Canadian entity, Manitoba Hydro may not be affected by this inconsistency but revision would provide clarity to the section. PRC-004-3 Application Guidelines: a) Under Definitions on page 20, it includes a note to add an example which includes various terms. It appears this was an internal note and meant to be deleted. b) On page 21 the standard states: Example: There are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that mean the Composite Protection System did not misoperate? This example does not appear to be answered thus the purpose and clarity of the example is in question. c) Also on page 21 the standard states: Paglow: A breaker failure operation does not, in itself, constitute a Misoperation On page 24 the standard states: Paglow: If the coordination error was at the remote terminal (set too fast), then it is an "Unnecessary Trip" at the remote location. If the coordination error was at the local terminal (set too slow), then it is a "Slow Trip" at the local location. What does “Paglow” refer to? It appears this was an internal note and meant to be deleted. d) On page 27 under the heading “Requirement 1” and on page 28 under the heading “Requirement 3” the standard states: The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure, it may decide to identify the

operation as a Misoperation and continue its investigation until the entity determines otherwise. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. It is redundant to add the same statement of intent in both of the Requirements. If the statement of intent must be stated in the Application Guidelines, it should appear once prior to the commencement of the Requirements sections.
Group
Bonneville Power Administration
Andrea Jessup
Yes
Yes
No.
Group
ACES Standards Collaborators
Jason Marshall
Yes
(1) We agree with the conceptual changes but believe some refinements are necessary. First, protection system is a NERC glossary term and should be capitalized. Second, the SDT should clarify what they mean by “affected.” Does this mean that amount of generation that was actually outaged as a result of the Misoperation? Or would this include an evaluation of the other potential Misoperations that could have occurred if the same conditions were experienced at other locations within the dispersed generation site? We believe that the answer should be the former rather than the latter. To make this clear, we suggest changing the word “affected” to “outaged.” (2) Based on a FERC informational filing previously communicated to the Commission by NERC, we believe that the clause on R2 and R3 should be “numbered” rather than “bulleted.” Numbers imply it is required where as bullets imply that there is an option from the list. This may be moot since there is only one option but for consistency with the filing and other NERC standards, we believe the bullet should be a sub-part of the requirement and replaced with a number.
Yes
(1) We agree with the conceptual changes to the Facilities section. However, the SDT should clarify what they mean by “affected.” Does this mean that amount of generation that was actually outaged as a result of the Misoperation or would this include an evaluation of the other potential Misoperations that could have occurred if the same conditions were experienced at other locations within the dispersed generation site? We believe that the answer should be the former rather than the latter. To make this clear, we suggest changing “affected” to “outaged.” (2) Additionally, there seems to be some other unrelated changes that would exceed the scope of the changes in the project SAR. While we do not see them as problematic, we question where they are coming from.
Group
DTE Electric
Kathleen Blacxk
Yes
Yes
No additional comments.
Group

Puget Sound Energy
Dianne Gordon
No
Technically this is ok, but is somewhat unclear. If we understand correctly, we recommend revising the wording as follows: "For Misoperations occurring on a portion of a dispersed generation collection of total aggregate rating greater than 75 MVA (and therefore a BES facility), if the aggregate rating of the portion of dispersed generation where the misoperation occurs is less or equal to 75 MVA, then this requirement does not apply."
Yes
Group
SPP Standards Review Group
Shannon V. Mickens
No
In the Rationale Box for Applicability reference is made several times to BES reliability. Then in the 7th line the emphasis switches over to the BPS. We prefer the references to the BES since the proposed change is being brought about by changes to the BES definition. We recommend the SDT use BES in these references for consistency.
No
Similar to the comment provided in response to Question 1 above, the Rationale box for Applicability contains references to both BES and BPS reliability. We recommend making all references to BES reliability. The definition of the new term 'Composite Protection System' needs to be mention in this draft standard for clarity.
Yes. In the 1st line of the Rationale Boxes in the Implementation Plans for PRC-004-2.1a(X) and PRC-004-3(X), change 'include' to 'includes'. We have a concern in reference to the name plate rating for dispersed generation and the value of 75 MVA. The exemption in both standards applies to anything below 75MVA aggregate. For consistency, we would ask that all other generation resources below 75 MVA be included in the exemption. In both Implementation Plans (PRC-004-2.1a(X) and PRC-004-3(X)), Balancing Authority shows up in the applicability sections. It should be deleted in both places.

Additional Comments

Flathead Electric Cooperative
Russ Schneider

"I still do support the concept of composite protection system. In addition, the way R2 is expanded to backup protection systems and the extra notifications required in 2.2 do not seem necessary or at least seem burdensome for backup protection system owners. I prefer the language in the previous draft."

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2014-01 Applicability for Dispersed Generation Resources Standards

The Dispersed Generation Resources Drafting Team (DGR SDT) thanks all commenters who submitted comments on the Standards. These standards were posted for a 45-day public comment period from July 10, 2014 through August 25, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 29 sets of comments, including comments from approximately 106 different people from approximately 77 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

This document contains the DGR SDT's response to all industry comments received during this comment period. The DGR SDT encourages commenters to review its responses to ensure all concerns have been addressed. The DGR SDT notes that a significant majority of commenters agree with the DGR SDT's recommendations on these standards, but that several commenters expressed specific concerns. Some comments supporting the DGR SDT's recommendations are discussed below but in most cases are not specifically addressed in this response. Also, several comments in response to specific questions are duplicated in other questions, and several commenters raise substantively the same concerns as others. Therefore, the DGR SDT's consideration of all comments is addressed in this section in summary form, with duplicate comments treated as a single issue.

1. Summary Consideration

Industry overwhelming agrees with the DGR SDT's recommendations to make applicability changes to account for the unique characteristics of DGRs in the NERC PRC-004 standard as evidenced by the initial ballot results. However, there are some disagreements among stakeholders and typographical errors contained in and illuminated by industry comments. The DGR SDT has carefully reviewed and considered each stakeholder comment and has revised its recommendations where suggested changes are adequately supported by a technical justification, consistent with the DGR SDT's intent, and consistent with industry consensus. The DGR SDT's summary consideration of comments follows.

2. General Comments

Industry identified a number of typographical and formatting errors in each of the posted high-priority standards PRC-004-2.1a(X) and PRC-004-3(X). The DGR SDT also identified additional typographical and formatting errors during its most recent review. The DGR SDT has corrected each identified typographical and formatting error as reflected in the posted redlined standards.

At least one commenter notes that "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." According to the commenter, this does not take Canadian legislation into account. The commenter believes the clause should refer to the definition in the NERC Rules of Procedure or in the applicable legislation in a jurisdiction governed by legislation other than the NERC Rules of Procedure.

The language cited by the commenter is boilerplate language that is used in every standard, and revising the language is outside the authority of this drafting team. Therefore, the DGR SDT has referred this concern to NERC staff for consideration.

3. Recommended Applicability Changes to PRC-004

At least one commenter disagrees with the placement of applicability statements within the requirement commenting that such statements generally should be placed in section 4 of the Standard unless some overriding clarity issue can be identified. The commenter proposes inserting the following statements in section 4 to more effectively communicate the applicability of distributed generation: "4.3.1 Those Protection Systems designed to protect BES distributed generation or associated collection systems regardless of voltage at points where the aggregate nameplate capacity is greater than 75 MVA. 4.3.2 Those protection systems associated with Bulk Electric System distributed generation where the aggregate nameplate capacity is equal or less than 75 MVA is not applicable." The commenter also is not clear on why the Bulk Electric System (BES) definition must be noted in the Standard, or why parallel usage of "dispersed power producing resources" should be followed. The commenter states that "distributed generation" is well understood and can be used while preserving the intent and clarity of the BES definition, and placement of applicability statements in this Standard is better suited in section 4.

The DGR SDT integrated applicability into the requirements section of PRC-004-2.1a(X), as it was deemed that creating a facilities section in PRC-004.2.1a would also require addressing what facilities were included as well as excluded, which would involve non-dispersed power producing resources. As the DGR SDT is focused on addressing dispersed power producing resources, this additional classification of non-dispersed power producing resources was deemed to be out of scope for this project. The DGR SDT believes that the proposed language as it exists adequately describes the treatment of dispersed power producing resources, a position that is supported by clear industry consensus.

The DGR SDT included reference to the BES definition to specifically link the proposed changes to the BES definition. The DGR SDT has fielded numerous comments that would be addressed through such a direct reference to the BES definition which provides a definition and basis for the definition of dispersed power producing resources.

At least one commenter agrees with the specific revisions concerning only the changes to distributed generation but does not agree with the ongoing revisions through Project 2010-05.1 that are included in this revision, such as the owner of the BES interrupting device being required to initiate review in all scenarios as opposed to the entity that initiated the interrupting device's action. Therefore, the commenter indicates that it intends to vote negative, as this revision includes language from Project 2010-05.1 that the commenter does not find agreeable.

Other commenters note other disagreements with substantive portions of the Standard that do not specifically pertain to DGR applicability. For example, some commenters note that there are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that this means the Composite Protection System did not misoperate? The commenter also recommends deleting "Paglow" in various locations.

The scope of the DGR SDT is to specifically address Standards applicability to dispersed power producing resources identified under Inclusion I4 of the BES definition. Therefore, these comments will be provided to NERC staff and to the Project 2010-5.1 SDT to the extent it remains active on these issues, as the DGR SDT believes these issues should be addressed on a broader and technology-neutral scope.

Some commenters note that the Effective Date sections in the implementation plan and the standard are not consistent. The DGR SDT has corrected language in the implementation plan and referenced the implementation plan in the standard to correct errors and eliminate redundancy.

At least one commenter notes that "Protection System" is a NERC Glossary term and should be capitalized in PRC-004. Second, the commenter believes the DGR SDT should clarify what they mean by "affected" by changing the word "affected" to "outaged."

The DGR SDT agrees with the recommendation to use the NERC Glossary term "Protection System" in PRC-004 and has therefore made these corrections in the posted versions. The use of the term "affected" instead of "outaged" was intended to address the situation in which a Protection System failed to trip a generator(s) and create an outage. This situation is also a "Misoperation" and would not be addressed by the use of "tripped" or "outaged."

At least one commenter notes that in the Rationale Box for Applicability, reference is made several times to BES reliability, then in the seventh line the emphasis switches over to the BPS. The commenter prefers the references to the BES since the proposed change is being brought about by changes to the BES definition, and recommends the DGR SDT use BES in these references for consistency.

The DGR SDT referenced Bulk Power System reliability in an effort to include applicability to non-BES elements/components of a facility. However, In light of this comment the DGR SDT has reevaluated its use of BES and BPS and determined that it may be appropriate to reference only the BES. The DGR SDT therefore adopts the commenter's suggestion and has made changes to the redlined standards accordingly.

At least one commenter believes that in Requirements R2 and R3 of PRC-004-2.1a(X) and section 4.2.1.3 of PRC-004-4, "75 MVA" should be changed to "20 MVA" to make it comparable to I2 generators. The commenter believes that although the change to 20 MVA would have this standard apply to non-BES assets, many standards do likewise. The commenter notes that "Protection Systems," which are the subject of this standard, are non-BES. As written, according to the commenter, a reliability gap would be created between I4 generators and I2 generators. The commenter believes that the proposed change violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: "Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage."

In order to provide consistent requirements for all generation, the DGR SDT believes it is necessary to assess applicability on individual units greater than 20 MVA and aggregate generation greater than 75 MVA, which are thresholds that have been explicitly recognized and approved by FERC as an appropriate threshold for these types of facilities consistent with the revised BES definition. The DGR SDT therefore does not believe it would be appropriate to use different aggregation thresholds absent a robust technical justification to do so. Moreover, the DGR SDT does not believe that a reliability gap is created, nor any unfair competitive advantages are given as a result.

At least one commenter believes that in PRC-004-2.1a(X) and PRC-004-3 (X) Rationale for Applicability, the sentence that says "Misoperations occurring on the Protection Systems of individual generation...", is misleading because by definition (I4), the individual resources are BES, therefore misoperations occurring on the Protection Systems of individual resources would have an impact on BES reliability, while noting that "material impact" is not defined.

The DGR SDT carefully considered this issue and believes its explanation in the rationale section is clear. Based on industry consensus on this issue and a lack of a clear technically justified reason supporting alternative language, the DGR SDT respectfully declines to adopt the commenter's suggestion.

At least one commenter notes that Requirements R2 and R3 of PRC-004-2.1a(X) and the Facilities section 4.2.1.3 of PRC-004-4 reference "individual" dispersed generator Protection Systems and the "'total" aggregate, which the commenter believes is still creating some confusion. According to the commenter, it appears that focus is on the "total" aggregate location not individual resources. The commenter questions whether it is correct to assume if there are multiple resource owners who each have less than 75 MVA but the multiple resources aggregate at a "utility" bus, the bus is the aggregate point and would only need to be reported if at this aggregate point the loss of the aggregate is greater than 75 MVA. The commenter also is concerned that several non-dispersed generator resources that may not be required to be registered that aggregate to greater than 75 MVA will have to be reported by utilities who do not own the equipment.

The applicability of these requirements for dispersed power producing resources is when an event occurs and affects a total of greater than 75 MVA nameplate rating. In this situation, misoperation analysis of the protection systems must be done at the individual generator level for each of the generators affected. If an event occurs and 75 MVA nameplate of generation or less is affected then no analysis is required. In the case of multiple owners of resources that aggregate to greater than 75 MVA nameplate at a "utility bus", the DGR SDT notes that if the site as a whole meets the criteria for being designated as BES (regardless of how many individual owners own portions of the site) each one of these owners should be registered as a generator owner/operator. These individual resource owners would then be responsible for performing a misoperation analysis on the individual generators they own IF the misoperation occurred on the generators themselves and the event affected greater than 75 MVA of nameplate generation at the site level (from the BES perspective, it does not matter if the generation is owned by one or multiple resource owners). Regarding inclusion of non-dispersed power producing resources, the DGR SDT believes that the appropriate generators were addressed with the proposed changes through the reference to "resources identified under Inclusion I4 of the BES Definition…", as the scope of the DGR SDT was limited to address dispersed power producing resources only.

A. PRC-004-2.1a(X)

At least one commenter notes that in Requirements R2 and R3, the words "or could have affected" were initially added but then deleted. The commenter believes those words should not have been deleted because the DGR PRC subteam had indicated that those words would be included. The deleted words addressed the commenter's concern it expressed during the comment period for the Dispersed Generation White Paper. Specifically, the commenter stated that it does not agree with limiting the analysis requirement to a trip of greater than 75 MVA because that only accounts for very large occurrences that could be unusual. The commenter believes that smaller occurrences, however, may predict an unusual large occurrence that could impact reliability, and that the deleted words were in fact included in the "Standards Applicability Guidelines" that were circulated for comment but were ultimately not issued.

The DGR SDT considered all industry comments on this issue and determined that the use of "could have affected" was too vague, and that proving or disproving whether an event or a single misoperation could have affected 75 MVA would be overly burdensome. The use of “affected” was determined to still be broad enough to include misoperations that did not result in an actual trip of the associated generator, for instance the situation in which a protection system failed to trip 75 MVA of nameplate generation when a trip should have occurred. Note that the proposed language revision does not refer to the actual generation of the site at the time of the event, but rather what the generators that experienced the misoperation(s) are capable of producing at nameplate rating. The DGR SDT believes that this addresses the concerns raised and therefore respectfully declines to adopt the commenter’s suggestion.

At least one commenter believes Requirements R2 and R3 should be approached in PRC-004-2.1a(X) the same as the exclusions in PRC-004-4. Rather than state that it is excluded at the end of the sentence, the commenter believes the Standard should simply state it on the front end, i.e. as follows: “This requirement does not apply to Misoperations occurring on the protection systems of individual dispersed generation power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected or could have affected an aggregate nameplate rating of less than or equal to 75 MVA of BES facilities.”

The DGR SDT considered the suggested approach; however, it was deemed that creating a similar facilities section in PRC-004.2.1a(X) would also require addressing what facilities were included as well as excluded, which would involve non-dispersed power producing resources. As the DGR SDT is limited to addressing dispersed power producing resources, this additional classification of non-dispersed power producing resources was deemed to be out of scope for this project. The DGR SDT considered industry comments on this issue and believes that the proposed language as it exists adequately describes the treatment of dispersed power producing resources.

At least one commenter believes that in order to clearly state that analysis of misoperations is exempted for dispersed generation within a group that meets the I4 criteria, the sub bullets under R2 and R3 should be revised to: ”For Misoperations occurring on the protection systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition.” Another commenter suggests that the language should be revised to “For Misoperations occurring on a portion of a dispersed generation collection of total aggregate rating greater than 75 MVA (and therefore a BES facility), if the aggregate rating of the portion of dispersed generation where the misoperation occurs is less or equal to 75 MVA, then this requirement does not apply."

The DGR SDT believes the current language clearly addresses the concern, as it is not the intent of the DGR SDT to exclude the Protection Systems on the individual dispersed power producing resources, but rather to define in which scenarios this analysis would need to be performed. Therefore, the DGR SDT respectfully declines to adopt the commenter’s suggestion.

At least one commenter observes that based on a FERC informational filing previously communicated to FERC by NERC, the commenter believes that the clause on R2 and R3 should be “numbered” rather than “bulleted,” as numbers imply it is required whereas bullets imply that there is an option from the list. The commenter notes that this may be moot since there is only one option but for consistency with the filing and other NERC standards, the commenter believes the bullet should be a sub-part of the requirement and replaced with a number.

In a standard, parts of a requirement that are set off with bullets are implied to be “OR” and parts that are numbered are “AND.” In this instance, there is only one bulleted item, so “OR” or “AND” qualifiers are not necessary. The DGR SDT consulted with NERC staff and determined that use of bullets in Requirements R2 and R3 is acceptable and consistent with previous uses. Therefore, the DGR SDT respectfully declines to modify the format of Requirements R2 and R3.

B. PRC-004-4

At least one commenter notes that the redlined standard posted on the project page is the redlined to an obsolete version of PRC-004-3, which was previously developed by the Project 2010-5.1 SDT. The commenter also notes that the rationale box for the Introduction states that the only revisions to this posting are to Section 4.2 Facilities, yet there are revisions indicated throughout the entirety of the posted standard. The commenter suggests taking the clean version of the final ballot passed PRC-004-3 and redline the Applicability Section changes only for entities to have a clear picture of what the standard is going to be.

The DGR SDT recognizes the concerns raised by the commenter and notes that proposed PRC-004-4 addresses these concerns.

At least one commenter notes that PRC-004-3 Application Guidelines, under Definitions on page 20, includes a note to add an example which includes various terms. It appears this was an internal note and meant to be deleted. The DGR SDT has removed the internal notes under the definitions section on page 20.

At least one commenter believes proposed Applicability 4.2.1.3 may be lead to misunderstanding. According to the commenter, if failure (or slow trip) of a Protection System of an individual dispersed power producing resource, identified under Inclusion I4 of the BES definition, affects the aggregate nameplate rating of over 75 MVA of BES Facilities, it seems like that Protection System operation would be applicable to the standard. If so, according to the commenter, clarification may be needed in the Application Guidelines, or the Applicability may need to be reworded, to help avoid a misunderstanding in which an entity thinks that the Protection System is not applicable to the standard.

The DGR SDT believes that the proposed language adequately describes the applicability and that addressing specific instances could potentially be more confusing as defining every specific instance would be a significant undertaking and that the applicability of specific instances which are not mentioned would then be questioned. However, in the case described in the comment the Protection System operation would be applicable.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

N/A

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

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Ben Wu	Orange and Rockland Utilties Inc.	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5

				1	2	3	4	5	6	7	8	9	10
4.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

N/A

				1	2	3	4	5	6	7	8	9	10
5.	Group	Connie Lowe	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton		NPCC	5
2.	Louise Slade		RFC	5, 6
3.	Randi Heise		SERC	1, 3, 5, 6
4.	Chip Humphrey		SERC	5
5.	Jeffrey Bailey		NPCC	5
6.	Larry Nash		SERC	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
6.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X		X	X				

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joseph Depoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Utilities District	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	David Greene	SERC Protection and Controls Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren		
2.	David Greene	SERC		
3.	Steve Edwards	Dominion		
4.	John Miller	Georgia Transmission Corporation		
5.	Charlie Fink	Entergy		

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Greg Campoli	IRC Standards Review Commitee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ali Miremadi	CAISO	WECC	2
2.	Ben Li	IESO	NPCC	2
3.	Charles Yeung	SPP	SPP	2
4.	Cheryl Moseley	ERCOT	ERCOT	2

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

5. Lori Spence	MISO	MRO	2
6. Matt Goldberg	ISONE	NPCC	2
7. Stephanie Monzon	PJM	RFC	2

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Pamela Hunter	Southern Company: Southern Company Services, Inc; Alabama Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				

N/A

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Andrea Jessup	Bonneville Power Administration	X		X			X				

Additional Member	Additional Organization	Region	Segment Selection
1. Ron Sporseen	Planning & Asset Management	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Jason Marshall	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Bob Solomon	Hoosier Energy	RFC	1
2. John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
3. John Shaver	Southwest Transmission Cooperative	WECC	1
4. Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
5. Ginger Mercier	Prairie Power	SERC	3
6. Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
7. Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Kathleen Blacxk	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	NERC Compliance	RFC	3
2. Daniel Herring	NERC Training & Standards Development	RFC	4
3. Mark Stefaniak	Merchant Operations	RFC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Dianne Gordon	Puget Sound Energy	X		X		X					

N/A

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Shannon V. Mickens	SPP Standards Review Group		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Louis Guidry	Cleco Power LLC	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

2.	Karl Diekevers	Nebraska Public Power District	MRO	1, 3, 5
3.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
6.	Wes Mizell	Westar Energy	SPP	1, 3, 5, 6
7.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
8.	James Nail	City of Independence, MO	SPP	3, 5
9.	Ron Losh	Southwest Power Pool	SPP	2
10.	Shannon Mickens	Southwest Power Pool	SPP	2
11.	Robert Rhodes	Southwest Power Pool	SPP	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
16.	Individual	Joshua Andersen	Salt River Project	X		X		X	X				
17.	Individual	Richard Vine	California ISO		X								
18.	Individual	Anthony Jablonski	ReliabilityFirst										X
19.	Individual	Maryclaire Yatsko	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
20.	Individual	Russell A. Noble	Public Utility District No. 1 of Cowlitz County, WA			X	X	X					
21.	Individual	Marc Donaldson	Tacoma Power	X		X	X	X	X				
22.	Individual	David Jendras	Ameren	X		X		X	X				
23.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
24.	Individual	Jonathan Meyer	Idaho Power Co.	X									
25.	Individual	John Pearson / Matt Goldberg	ISO New England		X								
26.	Individual	John Miller	Georgia Transmission Corporation	X									
27.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
28.	Individual	Jason Marshall	New England States Committee on Electricity (NESCOE)										
29.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The DGR SDT thanks all commenters for their comments and refers the reader to the summary response above.

Organization	Agree	Supporting Comments of "Entity Name"
Colorado Springs Utilities	Agree	Public Service Enterprise Group (PSEG)
California ISO	Agree	ISO/RTO Council Standards Review Committee
Ameren	Agree	Ameren agrees with and supports the SERC PCS comments for Project 2014-01 Dispersed Generation Resources - PRC-004.

1. Do you agree with the revisions made in proposed PRC-004-2.1a(X) to clarify applicability of PRC-004-2.1a to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

Summary Consideration: The DGR SDT thanks all commenters for their comments and refers the reader to the summary response above.

Organization	Yes or No	Question 1 Comment
SERC Protection and Controls Subcommittee	No	Requirements 2 and 3 reference “individual” dispersed generator Protection Systems and the “‘total” aggregate which is still creating some confusion. It appears that focus is on the “total” aggregate location not individual resources. Is it correct to assume if there are multiple resource owners who each have less than 75 MVA but the multiple resources aggregate at a “utility” bus, the bus is the aggregate point and would only need to be reported if at this aggregate point the loss of the aggregate is greater than 75MVA? There is also a concern that several non dispersed generator resources that may not be required to be registered that aggregate to greater than 75 MVA will have to be reported by utilities who do not own the equipment. Wording clarification and supporting Figures may need to be revised to clarify these requirements.
IRC Standards Review Commitee	No	In order to clearly state that analysis of misoperations is exempted for dispersed generation within a group that meets the I4 criteria, the sub bullets under R2 and R3 should be revised to:”For Misoperations occurring on the protection systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition.”

Organization	Yes or No	Question 1 Comment
Puget Sound Energy	No	Technically this is ok, but is somewhat unclear. If we understand correctly, we recommend revising the wording as follows:"For Misoperations occurring on a portion of a dispersed generation collection of total aggregate rating greater than 75 MVA (and therefore a BES facility), if the aggregate rating of the portion of dispersed generation where the misoperation occurs is less or equal to 75 MVA, then this requirement does not apply."
SPP Standards Review Group	No	In the Rationale Box for Applicability reference is made several times to BES reliability. Then in the 7th line the emphasis switches over to the BPS. We prefer the references to the BES since the proposed change is being brought about by changes to the BES definition. We recommend the SDT use BES in these references for consistency.
ISO New England	No	: In R2 and R3, the words “or could have affected” were initially added but then they were deleted. Those words should not have been deleted. The PRC subteam had indicated to us that those words would be included. The deleted words addressed the concern we expressed during the comment period for the Dispersed Generation White Paper. Specifically, we stated that we do not agree with limiting the analysis requirement to a trip of greater than 75 MVA because that only accounts for very large occurrences that could be unusual. Smaller occurrences, however, may predict an unusual large occurrence that could impact reliability. The deleted words were in fact included in the “Standards Applicability Guidelines” that were circulated for comment but were ultimately not issued. The deleted words “or could have affected” should be added back in.
Georgia Transmission Corporation	No	R2 and R3 should be approached in 004-2.1a the same as the exclusions in 004-3. Rather than state that it is excluded at the end of the sentence, simply state it on the front end.i.e. as follows:This requirement does not

Organization	Yes or No	Question 1 Comment
		apply to Misoperations occurring on the protection systems of individual dispersed generation power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected or could have affected an aggregate nameplate rating of less than or equal to 75 MVA of BES facilities.
Public Service Enterprise Group	No	In R2 and R3, "75MVA" should be changed to "20MVA." This would make it comparable to I2 generators. Although the change to 20MVA would have this standard apply to non-BES assets, many standards do likewise. In fact "Protection Systems," which are the subject of this standard, are non-BES. As written, a reliability gap would be created between I4 generators and I2 generators.The proposed change violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: "Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage." If alternative language was proposed that required the same 75MVA threshold for I2 generators, PSEG would be fine with that. But the proposed non-comparable treatment of generators is not acceptable.
Duke Energy	Yes	
Northeast Power Coordinating Council	Yes	The definition of the BES will lead to additional costs imposed on renewable generation that could inhibit the development of these resources. In New England in particular, states have enacted aggressive renewable energy polices and are actively working to implement them cost-effectively. The SDT's efforts recognize the unique design and operating characteristics of dispersed generation resources such as wind and solar facilities. At the same time, as expressed in the SDT's April 14, 2014 Draft White Paper, any revisions are intended to ensure that they do not "create a reliability gap." These are critical considerations. The SDT is appropriately evaluating how the obligations imposed on these asset owners and operators translate to reliability benefits, which is consistent with larger efforts within NERC to

Organization	Yes or No	Question 1 Comment
		incorporate cost-effectiveness analyses into the standards development process. As is the case with all standards, the revisions here would be subject to ongoing evaluation of further changes in light of experience and, in this case, the likely increased integration of dispersed power resources.The initiation of this project is beneficial to industry and this SDT's advancement of the objectives set forth in the Draft White Paper. To provide the owners and operators of dispersed generation resources (and potential future developers) with an expectation of their compliance obligations and associated costs, this effort should move forward as expeditiously as possible.
Arizona Public Service Company	Yes	
Dominion	Yes	
MRO NERC Standards Review Forum	Yes	
Southern Company: Southern Company Services, Inc; Alabama Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Looks good - removing the speculative "could have" language is helpful.
Bonneville Power Administration	Yes	
ACES Standards Collaborators	Yes	(1) We agree with the conceptual changes but believe some refinements are necessary. First, protection system is a NERC glossary term and should be capitalized. Second, the SDT should clarify what they mean by "affected." Does this mean that amount of generation that was actually outaged as a result of the Misoperation? Or would this include an evaluation of the other potential Misoperations that could have occurred if

Organization	Yes or No	Question 1 Comment
		the same conditions were experienced at other locations within the dispersed generation site? We believe that the answer should be the former rather than the latter. To make this clear, we suggest changing the word "affected" to "outaged." (2) Based on a FERC informational filing previously communicated to the Commission by NERC, we believe that the clause on R2 and R3 should be "numbered" rather than "bulleted." Numbers imply it is required where as bullets imply that there is an option from the list. This may be moot since there is only one option but for consistency with the filing and other NERC standards, we believe the bullet should be a sub-part of the requirement and replaced with a number.
DTE Electric	Yes	
Kansas City Power and Light	Yes	
Salt River Project	Yes	
ReliabilityFirst	Yes	ReliabilityFirst votes in the affirmative because we believe the changes adequately address the concerns involving individual dispersed generation power producing resources. ReliabilityFirst provides the following comments for consideration:1. The term "protection system" is used in the newly added language but ReliabilityFirst believes this term should be capitalized since it is a NERC Defined Term (i.e., "Protection System").
Seminole Electric Cooperative, Inc.	Yes	
Public Utility District No. 1 of Cowlitz County, WA	Yes	Cowlitz PUD agrees with the outcome, but disagrees with the format. Please refer to the last question.
Tacoma Power	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
Idaho Power Co.	Yes	
New England States Committee on Electricity (NESCOE)	Yes	The New England States Committee on Electricity (NESCOE) appreciates the work of the Dispersed Generation Resources Standard Drafting Team (SDT) in moving forward important clarifications regarding the applicability of certain standards to dispersed power producing resources. NESCOE supports the specific revisions reflected in the identified PRC standards, as well as the general intent of this Project. In comments on the first draft of the proposed BES definition, NESCOE cautioned that the definition might lead to unnecessary costs imposed on renewable generation that could inhibit the development of these resources. That remains a concern in New England, where states have enacted aggressive renewable energy polices and are actively working to implement them cost-effectively. The SDT's efforts recognize the unique design and operating characteristics of dispersed generation resources such as wind and solar facilities. At the same time, as expressed in the SDT's April 14, 2014 Draft White Paper, any revisions are intended to ensure that they do not "create a reliability gap." These are critical considerations. The SDT is appropriately evaluating how the obligations imposed on these asset owners and operators translate to reliability benefits, which is consistent with larger efforts within NERC to incorporate cost-effectiveness analyses into the standards development process. As with all standards, the revisions here would be subject to ongoing evaluation of further changes in light of experience and, in this case, the likely increased integration of dispersed power resources.NESCOE appreciates the initiation of this project and this SDT's advancement of the objectives set forth in the Draft White Paper. To provide the owners and operators of dispersed generation resources (and potential future developers) with an expectation of their compliance obligations and

Organization	Yes or No	Question 1 Comment
		associated costs, NERC should work to move this effort forward as expeditiously as possible. Thank you for your consideration of these comments.
Manitoba Hydro	Yes	D 1.1 states: "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" This does not take Canadian legislation into account. The clause should refer to the definition in the NERC Rules of Procedure or in the applicable legislation in a jurisdiction governed by legislation other than the NERC Rules of Procedure.
Colorado Springs Utilities		

2. **Do you agree with the revisions made in proposed PRC-004-3(X) to clarify applicability of PRC-004-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes**

Summary Consideration: The DGR SDT thanks all commenters for their comments and refers the reader to the summary response above.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	Refer to the response to Question 1. In addition, the redlined standard posted on the project page is the redlined Draft 4: January 17, 2014 of PRC-004-3 (Project 2010-5.1). There have been two drafts of PRC-004-3 after that and the latest Draft 6 has passed its final ballot. The Rationale Box for the Introduction (the Rationale Box does not have a title) states that the only revisions to this posting are to Section 4.2 Facilities, yet there are revisions indicated throughout the entirety of the posted standard. There are some important changes that have been approved in Draft 6 that are missing in the redlined version posted for Project 2014-01. Suggest taking the clean version of the final ballot passed PRC-004-3 and redline the Applicability Section changes only for entities to have a clear picture of what the standard is going to be. You cannot have two different versions of the same standard being balloted under different projects. The similar comment applies to the posted PRC-004-2.1a(X). The untitled Rationale Box for the Introduction states that the only revisions are to R2 and R3, yet there is redlining throughout the standard.
SERC Protection and Controls Subcommittee	No	Facilities section 4.2.1.3 references “individual” dispersed generator Protection Systems and the “‘total” aggregate which is still creating some confusion. It appears that focus is on the “total” aggregate location not individual resources. Is it correct to assume if there are multiple resource owners who each have less than 75 MVA but the multiple resources aggregate at a “utility” bus, the bus is the aggregate point and would only need to be reported if at this aggregate point the loss of the aggregate is

Organization	Yes or No	Question 2 Comment
		greater than 75MVA? There is also a concern that several non-dispersed generator resources that may not be required to be registered that aggregate to greater than 75 MVA will have to be reported by utilities who do not own the equipment. Wording clarification and supporting Figures may need to be revised to clarify these requirements.
IRC Standards Review Commitee	No	The comment is the same as the one providedT above in response to question 1.
SPP Standards Review Group	No	Similar to the comment provided in response to Question 1 above, the Rationale box for Applicability contains references to both BES and BPS reliability. We recommend making all references to BES reliability. The definition of the new term 'Composite Protection System' needs to be mention in this draft standard for clarity.
Seminole Electric Cooperative, Inc.	No	Seminole agrees with the specific revisions concerning only the changes to distributed generation, however, Seminole does not agree with the ongoing revisions through Project 2010-05.1 that are included in this revision, such as the owner of the BES interrupting device being required to initiate review in all scenarios as opposed to the entity that initiated the interrupting device's action. Therefore, Seminole must vote negative as this revision includes language from Project 2010-05.1 that Seminole does not find agreeable.
Tacoma Power	No	Proposed Applicability 4.2.1.3 may be lead to misunderstanding. If failure (or slow trip) of a Protection System of an individual dispersed power producing resource, identified under Inclusion I4 of the BES definition, affects the aggregate nameplate rating of over 75 MVA of BES Facilities, it seems like that Protection System operation would be applicable to the standard. If so, clarification may be needed in the Application Guidelines, or the Applicability may need to be reworded, to help avoid a misunderstanding in which an entity thinks that the Protection System is not applicable to the standard.

Organization	Yes or No	Question 2 Comment
ISO New England	No	: In R2 and R3, the words "or could have affected" were initially added but then they were deleted. Those words should not have been deleted. The PRC subteam had indicated to us that those words would be included. The deleted words addressed the concern we expressed during the comment period for the Dispersed Generation White Paper. Specifically, we stated that we do not agree with limiting the analysis requirement to a trip of greater than 75 MVA because that only accounts for very large occurrences that could be unusual. Smaller occurrences, however, may predict an unusual large occurrence that could impact reliability. The deleted words were in fact included in the "Standards Applicability Guidelines" that were circulated for comment but were ultimately not issued. The deleted words "or could have affected" should be added back in.
Public Service Enterprise Group	No	In 4.2.1.3, "75MVA" should be changed to "20MVA." This would make it comparable to I2 generators. Although the change to 20MVA would have this standard apply to non-BES assets, many standards do likewise. In fact "Protection Systems," which are the subject of this standard, are non-BES. As written, a reliability gap would be created between I4 generators and I2 generators.The proposed change violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: "Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage." If alternative language was proposed that required the same 75MVA threshold for I2 generators, PSEG would be fine with that. But the proposed non-comparable treatment of generators is not acceptable.
Duke Energy	Yes	
Arizona Public Service Company	Yes	
Dominion	Yes	

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Forum	Yes	
Southern Company: Southern Company Services, Inc; Alabama Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Looks good - focusing on "Misoperations that affected > 75 MVA" is appropriate.
Bonneville Power Administration	Yes	
ACES Standards Collaborators	Yes	(1) We agree with the conceptual changes to the Facilities section. However, the SDT should clarify what they mean by "affected." Does this mean that amount of generation that was actually outaged as a result of the Misoperation or would this include an evaluation of the other potential Misoperations that could have occurred if the same conditions were experienced at other locations within the dispersed generation site? We believe that the answer should be the former rather than the latter. To make this clear, we suggest changing "affected" to "outaged."(2) Additionally, there seems to be some other unrelated changes that would exceed the scope of the changes in the project SAR. While we do not see them as problematic, we question where they are coming from.
DTE Electric	Yes	
Puget Sound Energy	Yes	
Kansas City Power and Light	Yes	Page 21 Example: There are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential

Organization	Yes or No	Question 2 Comment
		relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that this means the Composite Protection System did not misoperate?.Also recommend deleting Paglow: in various locations.
Salt River Project	Yes	
Public Utility District No. 1 of Cowlitz County, WA	Yes	Cowlitz PUD agrees with the outcome, but disagrees with the format. Please refer to the last question.
American Electric Power	Yes	
Idaho Power Co.	Yes	
Georgia Transmission Corporation	Yes	The statement is made at the beginning of 4.2.1 "with the following exclusions:". That makes the I4 statement much clearer than the wording in 004-2.1a.
New England States Committee on Electricity (NESCOE)	Yes	See comments above.
Manitoba Hydro	Yes	The Effective Date sections in the implementation plan and the standard at section 6 are not consistent. The standard section distinguishes Western Interconnection as having a different Effective Date from others. The Implementation plan makes no reference to this. The standard references dates of twelve months or twenty-four months after the date the standard is adopted or as otherwise provided for in that jurisdiction but the implementation plan does not make reference to these durations. As a Canadian entity, Manitoba Hydro may not be affected by this inconsistency but revision would provide clarity to the section. PRC-004-3 Application Guidelines:a) Under Definitions on page 20, it includes a note to add an example which includes various terms. It appears this was an internal note and meant to be deleted. b) On

Organization	Yes or No	Question 2 Comment
		page 21 the standard states: Example: There are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that mean the Composite Protection System did not misoperate?This example does not appear to be answered thus the purpose and clarity of the example is in question.c) Also on page 21 the standard states: Paglow: A breaker failure operation does not, in itself, constitute a MisoperationOn page 24 the standard states: Paglow: If the coordination error was at the remote terminal (set too fast), then it is an "Unnecessary Trip" at the remote location. If the coordination error was at the local terminal (set too slow), then it is a "Slow Trip" at the local location.What does "Paglow" refer to? It appears this was an internal note and meant to be deleted.d) On page 27 under the heading "Requirement 1" and on page 28 under the heading "Requirement 3" the standard states: The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation until the entity determines otherwise. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.It is redundant to add the same statement of intent in both of the Requirements. If the statement of intent must be stated in the Application Guidelines, it should appear once prior to the commencement of the Requirements sections.

3. **Do you have any additional comments to assist the DGR SDT in further developing its recommendations?**

Summary Consideration: The DGR SDT thanks all commenters for their comments and refers the reader to the summary response above.

Organization	Question 3 Comment
Public Utility District No. 1 of Cowlitz County, WA	Cowlitz PUD disagrees with the placement of applicability statements within the Requirement. Such statements generally should be placed in Section 4 of the Standard unless some overriding clarity issue can be identified. After review of the proposed reasons for the Standard revision, no discussion was found to explain why applicability statements were inserted into Requirements R2 and R3 rather than in Section 4. This commenter looked at the possible clarity issue at hand, but can't find justification for this construct. Inserting the following statements in Section 4 would more effectively communicate the applicability of distributed generation: "4.3.1 Those Protection Systems designed to protect BES distributed generation or associated collection systems regardless of voltage at points where the aggregate nameplate capacity is greater than 75 MVA. 4.3.2 Those protection systems associated with BES distributed generation where the aggregate nameplate capacity is equal or less than 75 MVA is not applicable." Of note, this commenter is not clear why the BES definition must be noted in the Standard, or why parallel usage of "dispersed power producing resources" should be followed. Cowlitz PUD respectfully submits that "distributed generation" is well understood and can be used while preserving the intent and clarity of the BES definition, and placement of applicability statements in this Standard is better suited in Section 4.
Duke Energy	Duke Energy would like to take this opportunity to thank the SDT for considering and implementing the recommendations we made. We believe these recommendations adequately address our initial concerns.

Organization	Question 3 Comment
Kansas City Power and Light	N/A
DTE Electric	No additional comments.
Southern Company: Southern Company Services, Inc; Alabama Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No.
Bonneville Power Administration	No.
Dominion	PRC-004-3 (x) o M2; since the subparts have been updated, 2.3 needs to be removed in M2. o Guidelines and Technical Basis section-Definitions; Protection System Definition - 4th bullet should be revised to remove the word “station” as this word is not in the currently approved definition of Protection System in the NERC glossary of terms.In the PRC-004-3 (X) implementation plan, under the effective date section, there is no mention of the differences/exception listed in this standard for the Western Interconnection effective dates, this should be updated.PRC-004-2.1a(X) and PRC-004-3 (X) Rationale for Applicability - The sentence that says “Misoperations occurring on the Protection Systems of individual generation...”, is misleading because by definition (I4), the individual resources are BES, therefore misoperations occurring on the Protection Systems of individual resources would have an impact on BES reliability, while noting that “material impact” is not defined.
Northeast Power Coordinating Council	Regarding RC-004-3 (x): o M2; since the subparts have been updated, 2.3 needs to be removed in M2. o Guidelines and Technical Basis section-Definitions; Protection System Definition - 4th bullet should be revised to remove the word “station” from within the parentheses to be consistent with the currently approved definition of Protection System in the Glossary of Terms Used in NERC Reliability Standards.In the PRC-004-3 (X) Implementation Plan, under the effective date section, there is no mention of the differences/exceptions listed in this standard for the Western

Organization	Question 3 Comment
	Interconnection effective dates. This should be updated.PRC-004-2.1a(X) and PRC-004-3 (X) Rationale for Applicability - The sentence that says “Misoperations occurring on the Protection Systems of individual generation...”, is misleading because by definition (I4), the individual resources are BES, therefore misoperations occurring on the Protection Systems of individual resources would have an impact on BES reliability, while noting that “material impact” is not defined. In PRC-005-2(X), suggest adding the term “non-dispersed” to the wording of Part 4.2.5 to read “Protection Systems for the following non-dispersed BES generator facilities . . . .”The same suggestion for PRC-005-3(X).There is confusion surrounding the concurrent development of PRC-004-2.1a(X) and PRC-004-3(X). Is the intent to have both these versions merged into one? If so, that should be made clear. If not, then the numbering for one or the other should be changed. The NERC Standards Numbering System stipulates that the “one-digit numeral identifying the version of that standard” is the last number in the standards number. PRC-004-2.1a(X) and PRC-004-3(X) deal with different topics.
SERC Protection and Controls Subcommittee	The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Tacoma Power	The implementation plans for PRC-004-2.1a(X) and PRC-004-3(X) do not tie the effective date of the standard revision to the effective date of the BES definition. This seems incongruent with the implementation plans for PRC-005-2(X), PRC-005-3(X), and PRC-005-X(X).
MRO NERC Standards Review Forum	The NSRF wishes to thank the SDT for including a very well written and industry needed Application Guidelines section of the proposed Standard. This should be mandatory for reviewed Standards.

Organization	Question 3 Comment
New England States Committee on Electricity (NESCOE)	While the deadline for providing comments on proposed revisions to PRC-005 and VAR-002 under this Project 2014-01 has passed, NESCOE supports these proposed changes for the same reasons discussed above and offers the following minor suggestions for clarity: o PRC-005-2(X) - suggest adding the term "non-dispersed" to the wording of 4.2.5 to read "Protection Systems for the following non-dispersed BES generator facilities . . . ." o PRC-005-3(X) - same suggestion.
SPP Standards Review Group	Yes.In the 1st line of the Rationale Boxes in the Implementation Plans for PRC-004-2.1a(X) and PRC-004-3(X), change 'include' to 'includes'.We have a concern in reference to the name plate rating for dispersed generation and the value of 75 MVA. The exemption in both standards applies to anything below 75MVA aggregate. For consistency, we would ask that all other generation resources below 75 MVA be included in the exemption.In both Implementation Plans (PRC-004-2.1a(X) and PRC-004-3(X)), Balancing Authority shows up in the applicability sections. It should be deleted in both places.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-2b. The standard previously was adopted by the NERC Board of Trustees on August 16, 2012, and approved by FERC on April 16, 2013. The intent of the revisions is to clarify application of Requirements R3 and R4 to Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

The only revisions made to this version of VAR-002 are revisions to Requirements R3 and R4, 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.

The revisions to the two Requirements were made to VAR-002-2b, which is the currently enforceable version of VAR-002. VAR-002-3 has been approved by FERC; however, NERC may request approval of this interim version of the standard in order to provide regulatory certainty for entities as the revised definition of BES is being implemented. This interim version is labeled VAR-002-2b(X) for balloting purposes.

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-2b(X)
3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.
4. **Applicability**
   - **4.1.** Generator Operator.
   - **4.2.** Generator Owner.
5. **Effective Date:** The standard shall become effective on the date the standard is approved by an applicable government 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

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up[1] or shutdown[2] mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in the automatic voltage control mode for a reason other than start-up or shutdown.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within applicable Facility Ratings[4]) as directed by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

- Reporting of status or capability changes as stated in Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

Rationale for Requirement R3 Exclusion:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R3.1 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

[3] The voltage or Reactive Power schedule is a target value communicated by the Transmission Operator to the Generator Operator establishing a tolerance band within which the target value is to be maintained during a specified period.

[4] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this may lead to a change in the associated Facility Ratings.

standards such as proposed TOP-003 require the Generator Operator to provide real time data as directed by the TOP.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

4.1. For generator step-up and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

4.1.1. Tap settings.

4.1.2. Available fixed tap ranges.

4.1.3. Impedance data.

4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

Rationale for Footnote 5 in Requirement R4, Part 4.1:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR-002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

specified in Requirement 1. If a generator is being started up or shut down with the automatic voltage control off and no notification of the automatic voltage regulator status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode. Such evidence must include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's direction as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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. 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 Generator Operator shall maintain evidence needed for Measure 1 through Measure 4 and Measure 7 for the current and previous calendar year.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measures 5 and 6)

The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The responsible entity did not operate each generator in the automatic voltage control mode and failed to notify the Transmission Operator as identified in R1.
R2.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for up to and including 45 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 45 minutes up to and including 60 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator. OR The Generator Operator failed to provide an explanation of why the voltage schedule could not be met.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 60 minutes up to and including 75 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 75 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator and the Generator Operator failed to provide an explanation of why the voltage schedule could not be met.
R3.	N/A	N/A	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in either R3.1 or R3.2	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in both R3.1 and R3.2

R4.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner one of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 30, but less than or equal to 35 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner two of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 35, but less than or equal to 40 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner three of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 40, but less than or equal to 45 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner any of the types of data as specified in R4.1.1 and R 4.1.2 and 4.1.3 and 4.1.4 OR The information was provided in more than 45 calendar days of the request.
R5.	N/A	N/A	N/A	The responsible entity failed to ensure that transformer tap positions were changed according to the specifications provided by the Transmission Operator when said actions would not have violated safety, an equipment rating, a regulatory requirement, or a statutory requirement.
R5.1.	N/A	N/A	N/A	The responsible entity failed to notify the Transmission Operator and to provide technical justification.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 — Interpretation of Requirements R1 and R2 (August 1, 2007).

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	January 16, 2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	October 29, 2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	March 3, 2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	TBD	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4.	Revised
2b	August 16, 2012	Adopted by Board of Trustees	
2b	April 16, 2013	FERC Order issued approving VAR-002-2b	
2b(X)	TBD	Interim version to clarify applicability of two Requirements to BES dispersed power producing resources. Revised in Project 2014-01.	Revised

Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

Appendix 2

Interpretation of VAR-002-1a

Request:

VAR-002 — Generator Operation for Maintaining Network Voltage Schedules, addresses the generator's provision of voltage and VAR control. Confusion exists in the industry and regions as to which requirements in this standard apply to Generator Operators that operate generators that do not have automatic voltage regulation capability.

The Standard's requirements do not identify the subset of generator operators that need to comply – forcing some generator operators that do not have any automatic voltage regulation capability to demonstrate how they complied with the requirements, even when they aren't physically able to comply with the requirements. Generator owners want clarification to verify that they are not expected to acquire AVR devices to comply with the requirements in this standard.

Many generators do not have automatic voltage regulators and do not receive voltage schedules. These entities are at a loss as to how to comply with these requirements and are expending resources attempting to demonstrate compliance with these requirements. A clarification will avoid challenges and potential litigation stemming from sanctions and penalties applied to entities that are being audited for compliance with this standard, but who do not fall within the scope or intent of the standard itself.

Please identify which requirements apply to generators that do not operate generators equipped with AVRs.

Response: All the requirements and associated subrequirements in VAR-002-1a apply to Generator Owners and Generator Operators that own or operate generators whether equipped with an automatic voltage regulator or not. The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. A generator that is not equipped with an automatic voltage regulator results in a functionally equivalent condition to a generator equipped with an automatic voltage regulator that is out of service due to maintenance or failure.

There are no requirements in the standard that require a generator to have an automatic voltage regulator, nor are there any requirements for a Generator Owner to modify its generator to add an automatic voltage regulator. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-2b. The standard previously was adopted by the NERC Board of Trustees on August 16, 2012, and approved by FERC on April 16, 2013. The intent of the revisions is to clarify application of Requirements R3~~4~~ and R4~~5~~ to ~~BES~~ Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

The only revisions made to this version of VAR-002 are revisions to Requirements R3 and R4, 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.

The revisions to the two Requirements were made to VAR-002-2b, which is the currently enforceable version of VAR-002. VAR-002-3 ~~is pending regulatory approval~~has been approved by FERC; however, ~~, and depending on the timing of the approval of VAR-002-3,~~ NERC may request approval of this interim version of the standard in order to provide regulatory certainty for entities as the revised definition of BES is being implemented. This interim version is labeled VAR-002-2b(X) for balloting purposes.

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-2b(X)
3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.
4. **Applicability**

   4.1. Generator Operator.

   4.2. Generator Owner.
5. **Effective Date:** The standard shall become effective on the date the standard is approved by an applicable government 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

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up[1] or shutdown[2] mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in the automatic voltage control mode for a reason other than start-up or shutdown.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within applicable Facility Ratings[4]) as directed by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

- Reporting of status or capability changes as stated in Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

Rationale for Requirement R3 Exclusion:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R3.1 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

[3] The voltage or Reactive Power schedule is a target value communicated by the Transmission Operator to the Generator Operator establishing a tolerance band within which the target value is to be maintained during a specified period.

[4] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this may lead to a change in the associated Facility Ratings.

standards such as proposed TOP-003 require the Generator Operator to provide real time data as directed by the TOP.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

4.1. For generator step-up ~~transformers~~ and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

4.1.1. Tap settings.

4.1.2. Available fixed tap ranges.

4.1.3. Impedance data.

4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

Rationale for Footnote 5 in Requirement R4, Part 4.1:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR-002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection~~The Transmission Operator / Transmission Provider needs to review tap settings on the main transformers that connect the generation to the high voltage system. The Transmission Operator / Transmission Provider must assure that the collector system (typically 34.5 kV) voltage coordinates with the voltage set-points and tolerance bands established by the Transmission Operator / Transmission. The portion of the collector system that aggregates 75 MVA or less of resources is excluded under I4 and the individual unit step-up transformers primarily affect the collector system, so it should also be excluded and left to the Generator Owner to design and manage based on the secondary voltages expected on the collector system~~.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1. If a generator is being started up or shut down with the automatic voltage control off and no notification of the automatic voltage regulator status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode. Such evidence must include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's direction as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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. 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 Generator Operator shall maintain evidence needed for Measure 1 through Measure 4 and Measure 7 for the current and previous calendar year.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measures 5 and 6)

The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The responsible entity did not operate each generator in the automatic voltage control mode and failed to notify the Transmission Operator as identified in R1.
R2.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for up to and including 45 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 45 minutes up to and including 60 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator. OR The Generator Operator failed to provide an explanation of why the voltage schedule could not be met.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 60 minutes up to and including 75 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 75 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator and the Generator Operator failed to provide an explanation of why the voltage schedule could not be met.
R3.	N/A	N/A	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in either R3.1 or R3.2	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in both R3.1 and R3.2

R4.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner one of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 30, but less than or equal to 35 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner two of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 35, but less than or equal to 40 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner three of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 40, but less than or equal to 45 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner any of the types of data as specified in R4.1.1 and R 4.1.2 and 4.1.3 and 4.1.4 OR The information was provided in more than 45 calendar days of the request.
R5.	N/A	N/A	N/A	The responsible entity failed to ensure that transformer tap positions were changed according to the specifications provided by the Transmission Operator when said actions would not have violated safety, an equipment rating, a regulatory requirement, or a statutory requirement.
R5.1.	N/A	N/A	N/A	The responsible entity failed to notify the Transmission Operator and to provide technical justification.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 — Interpretation of Requirements R1 and R2 (August 1, 2007).

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	January 16, 2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	October 29, 2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	March 3, 2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	TBD	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4.	Revised
2b	August 16, 2012	Adopted by Board of Trustees	
2b	April 16, 2013	FERC Order issued approving VAR-002-2b	
2b(X)	TBD	Interim version to clarify applicability of two Requirements to BES dispersed power producing resources. Revised in Project 2014-01.	Revised

Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

Appendix 2

Interpretation of VAR-002-1a

Request:

VAR-002 — Generator Operation for Maintaining Network Voltage Schedules, addresses the generator's provision of voltage and VAR control. Confusion exists in the industry and regions as to which requirements in this standard apply to Generator Operators that operate generators that do not have automatic voltage regulation capability.

The Standard's requirements do not identify the subset of generator operators that need to comply – forcing some generator operators that do not have any automatic voltage regulation capability to demonstrate how they complied with the requirements, even when they aren't physically able to comply with the requirements. Generator owners want clarification to verify that they are not expected to acquire AVR devices to comply with the requirements in this standard.

Many generators do not have automatic voltage regulators and do not receive voltage schedules. These entities are at a loss as to how to comply with these requirements and are expending resources attempting to demonstrate compliance with these requirements. A clarification will avoid challenges and potential litigation stemming from sanctions and penalties applied to entities that are being audited for compliance with this standard, but who do not fall within the scope or intent of the standard itself.

Please identify which requirements apply to generators that do not operate generators equipped with AVRs.

Response: All the requirements and associated subrequirements in VAR-002-1a apply to Generator Owners and Generator Operators that own or operate generators whether equipped with an automatic voltage regulator or not. The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. A generator that is not equipped with an automatic voltage regulator results in a functionally equivalent condition to a generator equipped with an automatic voltage regulator that is out of service due to maintenance or failure.

There are no requirements in the standard that require a generator to have an automatic voltage regulator, nor are there any requirements for a Generator Owner to modify its generator to add an automatic voltage regulator. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

The only revisions made to this version of VAR-002 are revisions to Requirements R3 and R4, 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.

The revisions to the two Requirements were made to VAR-002-2b, which is the currently enforceable version of VAR-002. VAR-002-3 has been approved by FERC; however, NERC may request approval of this interim version of the standard in order to provide regulatory certainty for entities as the revised definition of BES is being implemented. This interim version is labeled VAR-002-2b(X) for balloting purposes.

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-2b(X)
3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.
4. **Applicability**

   4.1. Generator Operator.

   4.2. Generator Owner.
5. **Effective Date:** ~~In those jurisdictions~~The standard shall become effective on the date the standard is approved by an applicable government authority or as otherwise provided for in a jurisdiction where ~~regulatory~~ approval by an applicable governmental authority is required~~, this~~ 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 ~~applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this 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 ~~approval~~or as otherwise provided for in that jurisdiction.

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up[1] or shutdown[2] mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in the automatic voltage control mode for a reason other than start-up or shutdown.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within applicable Facility Ratings[4]) as directed by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

- Reporting of status or capability changes as stated in Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

Rationale for Requirement R3 Exclusion: VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R3.1 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

[3] The voltage or Reactive Power schedule is a target value communicated by the Transmission Operator to the Generator Operator establishing a tolerance band within which the target value is to be maintained during a specified period.

[4] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this may lead to a change in the associated Facility Ratings.

standards such as proposed TOP-003 require the Generator Operator to provide real time data as directed by the TOP.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

4.1. For generator step-up ~~transformers~~ and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

4.1.1. Tap settings.

4.1.2. Available fixed tap ranges.

4.1.3. Impedance data.

4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

Rationale for Footnote 5 in Requirement R4, Part 4.1:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR-002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

specified in Requirement 1. If a generator is being started up or shut down with the automatic voltage control off and no notification of the automatic voltage regulator status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode. Such evidence must include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's direction as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

~~For entities that do not work for~~As defined in the ~~Regional Entity, the Regional Entity shall serve as the~~ NERC Rules of Procedure, "Compliance Enforcement Authority~~.~~

~~For functional entities that work for~~" means NERC or the Regional Entity in their ~~Regional Entity, the ERO or a Regional Entity approved by the ERO~~respective roles of monitoring and ~~FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.~~enforcing compliance with the NERC Reliability Standards.

1.2. 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 Generator Operator shall maintain evidence needed for Measure 1 through Measure 4 and Measure 7 for the current and previous calendar year.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measures 5 and 6)

The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The responsible entity did not operate each generator in the automatic voltage control mode and failed to notify the Transmission Operator as identified in R1.
R2.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for up to and including 45 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 45 minutes up to and including 60 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator. OR The Generator Operator failed to provide an explanation of why the voltage schedule could not be met.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 60 minutes up to and including 75 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 75 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator and the Generator Operator failed to provide an explanation of why the voltage schedule could not be met.
R3.	N/A	N/A	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in either R3.1 or R3.2	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in both R3.1 and R3.2

R4.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner one of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 30, but less than or equal to 35 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner two of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 35, but less than or equal to 40 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner three of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 40, but less than or equal to 45 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner any of the types of data as specified in R4.1.1 and R 4.1.2 and 4.1.3 and 4.1.4 OR The information was provided in more than 45 calendar days of the request.
R5.	N/A	N/A	N/A	The responsible entity failed to ensure that transformer tap positions were changed according to the specifications provided by the Transmission Operator when said actions would not have violated safety, an equipment rating, a regulatory requirement, or a statutory requirement.
R5.1.	N/A	N/A	N/A	The responsible entity failed to notify the Transmission Operator and to provide technical justification.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 — Interpretation of Requirements R1 and R2 (August 1, 2007).

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	January 16, 2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	October 29, 2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	March 3, 2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	TBD	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4.	Revised
2b	August 16, 2012	Adopted by Board of Trustees	
2b	April 16, 2013	FERC Order issued approving VAR-002-2b	
2b(X)	TBD	Interim version to clarify applicability of two Requirements to BES dispersed power producing resources. Revised in Project 2014-01.	Revised

Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

Appendix 2

Interpretation of VAR-002-1a

Request:

VAR-002 — Generator Operation for Maintaining Network Voltage Schedules, addresses the generator's provision of voltage and VAR control. Confusion exists in the industry and regions as to which requirements in this standard apply to Generator Operators that operate generators that do not have automatic voltage regulation capability.

The Standard's requirements do not identify the subset of generator operators that need to comply – forcing some generator operators that do not have any automatic voltage regulation capability to demonstrate how they complied with the requirements, even when they aren't physically able to comply with the requirements. Generator owners want clarification to verify that they are not expected to acquire AVR devices to comply with the requirements in this standard.

Many generators do not have automatic voltage regulators and do not receive voltage schedules. These entities are at a loss as to how to comply with these requirements and are expending resources attempting to demonstrate compliance with these requirements. A clarification will avoid challenges and potential litigation stemming from sanctions and penalties applied to entities that are being audited for compliance with this standard, but who do not fall within the scope or intent of the standard itself.

Please identify which requirements apply to generators that do not operate generators equipped with AVRs.

Response: All the requirements and associated subrequirements in VAR-002-1a apply to Generator Owners and Generator Operators that own or operate generators whether equipped with an automatic voltage regulator or not. The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. A generator that is not equipped with an automatic voltage regulator results in a functionally equivalent condition to a generator equipped with an automatic voltage regulator that is out of service due to maintenance or failure.

There are no requirements in the standard that require a generator to have an automatic voltage regulator, nor are there any requirements for a Generator Owner to modify its generator to add an automatic voltage regulator. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-3. The standard previously was adopted by the NERC Board of Trustees in May 2014 and is pending regulatory approval. The intent of the revisions is to clarify application of Requirements R4 and R5 to Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.	Revised
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised
3	5/7/2014	Adopted by NERC Board of Trustees	
3	8/1/2014	Approved by FERC in docket RD14-11-000	
4	TBD	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised

Definitions of Terms Used in the Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

When this standard has received ballot approval, the text boxes within the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   4.1. Generator Operator
   4.2. Generator Owner
5. **Effective Dates**

   The standard shall become effective on the later of the effective date of VAR-002-3, or the date the standard VAR-002-4 is approved by an applicable government 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.

The only revisions made to this version of VAR-002 are revisions to Requirements R4 and R5, 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.

The revisions to the two Requirements were made to VAR-002-3, which was approved by its ballot pool and adopted by the NERC Board in May 2014, VAR-002-3 is currently pending regulatory approval.

B. Requirements and Measures

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within each generating Facility's capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive

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[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for Exclusion in Requirement R4:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide real time data as directed by the TOP.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

5.1. For generator step-up and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

Rationale for Exclusion in Requirement R5:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

> transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR-002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

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 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-3. The standard previously was adopted by the NERC Board of Trustees in May 2014 and is pending regulatory approval. The intent of the revisions is to clarify application of Requirements R4 and R5 to Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

Version History

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1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
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1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
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3	5/7/2014	Adopted by NERC Board of Trustees	
3	8/1/2014	Approved by FERC in docket RD14-11-000	
4	TBD	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised

Definitions of Terms Used in the Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

When this standard has received ballot approval, the text boxes within the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Generator Operator
   - **4.2.** Generator Owner
5. **Effective Dates**

   The standard shall become effective on the later of the effective date of VAR-002-3, or the date the standard VAR-002-4 is approved by an applicable government 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.

The only revisions made to this version of VAR-002 are revisions to Requirements R4 and R5, 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.

The revisions to the two Requirements were made to VAR-002-3, which was approved by its ballot pool and adopted by the NERC Board in May 2014, VAR-002-3 is currently pending regulatory approval.

B. Requirements and Measures

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within each generating Facility's capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive

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[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition~~Reporting of reactive capability changes is not applicable to the individual for dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition~~.

Rationale for Exclusion in Requirement R4:
VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide real time data as directed by the TOP.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request~~Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability~~. *[Violation Risk Factor: ~~Medium~~Lower] [Time Horizon: Real-time Operations]*

5.1. For generator step-up ~~transformers~~ and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

Rationale for Exclusion in Requirement R5:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR-002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

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 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

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.

When this standard has received ballot approval, the text boxes within the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-~~3~~4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   4.1. Generator Operator
   4.2. Generator Owner

> The only revisions made to this version of VAR-002 are revisions to Requirements R4 and R5, 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.
>
> The revisions to the two Requirements were made to VAR-002-3, which was approved by its ballot pool and adopted by the NERC Board in May 2014, VAR-002-3 is currently pending regulatory approval.

5. **Effective Dates**

The standard shall become effective on the ~~first day~~later of the ~~first calendar quarter after~~effective date of VAR-002-3, or the date ~~that~~ the standard VAR-002-4 is approved by an applicable governmen~~tal~~t 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, ~~VAR-002-3~~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. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within each generating Facility's capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.
[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.
[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.
[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for Exclusion in Requirement R4:
VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide real time data as directed by the TOP.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

5.1. For generator step-up ~~transformers~~ and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

Rationale for Exclusion in Requirement R5:
The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR-002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

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 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
~~2b~~	~~8/16/2012~~	~~Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b. Adopted by Board of Trustees.~~	~~Revised~~
~~2b~~	~~4/16/2013~~	~~FERC Order issued approving VAR-002-2b~~	
~~3~~	~~5/6/2014~~	~~Adopted by the NERC Board of Trustees~~	
~~3~~	~~8/1/2014~~	~~FERC issued letter order approving VAR-002-3~~	

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:**~~

~~This requirement has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in either voltage controlling mode or the mode instructed by the TOP. However, the requirement has been modified to allow for testing, and the measure has been updated to include some of the evidence that can be used for compliance purposes.~~

~~**Rationale for R2:**~~

~~Requirement R2 details how a Generator Operator (GOP) operates its generator(s) to provide voltage support and when the GOP is expected to notify the Transmission Operator (TOP). In an effort to remove prescriptive notification requirements for the entire continent, the VAR-002-3 standard drafting team (SDT) opted to allow each TOP to determine the notification requirements for each of its respective GOPs based on system requirements. Additionally, a new Part 2.3 has been added to detail that each GOP may monitor voltage by using its existing facility equipment.~~

~~Conversion Methodology: There are many ways to convert the voltage schedule from one voltage level to another. Some entities may choose to develop voltage regulation curves for their transformers; others may choose to do a straight ratio conversion; others may choose an entirely different methodology. All of these methods have technical challenges, but the studies performed by the TOP, which consider N-1 and credible N-2 contingencies, should compensate for the error introduced by these methodologies, and the TOP possesses the authority to direct the GOP to modify its output if its performance is not satisfactory. During a significant system event, such as a voltage collapse, even a generation unit in automatic voltage control that controls based on the low-side of the generator step-up transformer should see the event on the low-side of the generator step-up transformer and respond accordingly.~~

~~Voltage Schedule Tolerances: The bandwidth that accompanies the voltage target in a voltage schedule should reflect the anticipated fluctuation in voltage at the GOP'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 GOP's AVR control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.~~

~~**Rationale for R3:**~~

~~This requirement has been modified to limit the notifications required when an AVR goes out of service and quickly comes back in service. Notifications of this type of status change provide little to no benefit to reliability. Thirty (30) minutes have been built into the requirement to allow a GOP time to resolve an issue before having to notify the TOP of a status change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change.~~

~~**Rationale for R4:**~~

~~This requirement has been bifurcated from the prior version VAR-002-2b Requirement R3. This requirement allows GOPs to report reactive capability changes after they are made aware of the change. The current standard requires notification as soon as the change occurs, but many GOPs are not aware of a reactive capability change until it has taken place.~~

~~**Rationale for R5:**~~

~~This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected. The prior version of VAR-002-2b, Requirement R4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed. The percentage information was not needed because the tap settings, ranges and impedance are required. Those inputs can be used to calculate the step-change percentage if needed.~~

~~**Rationale for R6:**~~

~~This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected.~~

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Implementation Plan

Dispersed Generation Resources
VAR-002-2b(X)

The standard numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to BOT adoption.

Standards Involved

Approval:

- VAR-002-2b(X) – Generator Operation for Maintaining Network Voltage Schedules

Retirement or Supersede:

- VAR-002-2b – Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including VAR-002, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

Effective Date

VAR-002-2b(X) shall become effective on the date the standard is approved by an applicable government 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.

Retirement of Existing Standards:

The existing standard VAR-002-2b shall be retired at midnight of the day immediately prior to the effective date of VAR-002-2b(X) to the extent it is not superseded by another version of VAR-002, e.g., VAR-002-3.

Implementation Plan

Dispersed Generation Resources
VAR-002-4

Standards Involved
Approval:

- VAR-002-4 – Generator Operation for Maintaining Network Voltage Schedules

Retirement or Supersede:

- VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals:
N/A

Background:
In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including VAR-002, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

Effective Date
VAR-002-4 shall become effective on the later of the effective date of VAR-002-3, or the date the VAR-002-4 is approved by an applicable government 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.

Retirement of Existing Standards:
Approved VAR-002-3 shall be retired at midnight of the day immediately prior to the effective date of VAR-002-4.

Unofficial Comment Form

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standards. The electronic comment form must be completed **by 8 p.m. Eastern on Thursday, October 16, 2014**.

If you have questions please contact Sean Cavote or by telephone at 404.446.9697.

All documents for this project are available on the project page.

Background Information

This posting solicits formal comments on VAR-002-4, one of three Project 2014-01 Dispersed Generation Resources (DGR) "high-priority" Reliability Standards as identified in the draft white paper (White Paper) prepared by the Project 2014-01 (Project) drafting team (DGR SDT). Please note that NERC posted recommended applicability changes to VAR-002-2b(X) on June 12, 2014. However, FERC approved VAR-002-3 on August 2, 2014, which supersedes VAR-002-2b(X) effective on October 1, 2014. Therefore, recommended applicability changes to VAR-002-2b(X) were not subsequently posted for ballot. VAR-002-4 would supersede the recently approved VAR-002-3 upon successful ballot and final regulatory approval of that version.

The goal of the Project is to ensure that the Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System, as the characteristics of operating dispersed power producing resources can be unique. In light of the revised Bulk Electric System (BES) definition approved by the Federal Energy Regulatory Commission in 2014, the intent of this Project is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources where the status quo does not create a reliability gap.

The DGR SDT performed a review of all standards that apply to GOs and GOPs and categorized how each standard should be applied to dispersed power producing resources to accomplish the reliability purpose of the standard. The DGR SDT developed the White Paper to explain its approach, which was posted on April 17, 2014 for an informal comment period.[1] The industry feedback received on the White Paper allowed the DGR SDT to refine its approach and finalize recommended revisions to the standards. As part of this review the DGR SDT determined that there are three high-priority standards in which immediate attention is required to provide direction to industry stakeholders as soon as feasible regarding how to appropriately direct compliance related preparations:

[1] The current version of the White Paper can be downloaded on the Project web page at http://www.nerc.com/pa/Stand/Pages/Project-2014-01-Standards-Applicability-for-Dispersed-Generation-Resources.aspx.

- PRC-004;[2]
- PRC-005;[3] and
- VAR-002.

The DGR SDT responded to industry comments as contained in its Consideration of Comments, which is included with this posting.

The DGR SDT continues to coordinate with other NERC Reliability Standards projects currently under development to ensure continuity and to develop a posting strategy that ensures all applicability changes approved by ballot are filed and implemented as quickly as possible without adversely impacting other projects.

Summary of Proposed Changes

The DGR's recommended changes are limited to revising the applicability of VAR-002 to appropriately exclude certain dispersed power producing resources from the standard. Although the redlined version of VAR-002 included with this posting contains changes that appear structurally different, the substance of VAR-002 remains the same.

The drafting team has posted the following standard, along with its corresponding implementation plan:

- VAR-002-4 (clean and redlined against the previously posted VAR-002-4)
  In addition, the drafting team has posted the following supporting document:
- DGR SDT Response to Comments on PRC-005 and VAR-002

Please note that the DGR SDT has not revised the Violation Risk Factors (VRFs) or Violation Severity Levels (VSLs) associated with VAR-002 because the proposed revisions do not change the reliability intent or impact of any of the requirements. If the applicability recommendations are approved by industry, the DGR SDT's intent is that the VRFs and VSLs for each requirement would be unchanged from VAR-002-3.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

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[2] The DGR SDT posted applicability revisions to relevant versions of PRC-004 for comment and ballot from July 10, 2014 to August 25, 2014, after the comment period and ballot of that standard in Project 2010-05.1 concluded.

[3] The DGR SDT posted applicability revisions to relevant versions of PRC-005 for comment and ballot from June 12, 2014 to July 29, 2014. Relevant versions of that standard are now posted for final ballot.

Questions

1. Do you agree with the revisions made in proposed VAR-002-4 to clarify applicability of VAR-002-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

2. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

   Yes:

   No:

   Comments:

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Project 2014-01 Dispersed Generation Resources

DRAFT Plan for Standards Drafting Team (SDT) Coordination and Balloting Multiple Versions of Standards | June 12, 2014

Background

Pursuant to the Standards Authorization Request for this project posted on November 20, 2014, the Project 2014-01 Dispersed Generation Resources (DGR) SDT proposes to modify PRC-004-2.1a, PRC-004-3, PRC-005-2, PRC-005-3, PRC-005-X, VAR-002-2b, and VAR-002-3 to account for the unique characteristics of dispersed power producing resources. As the DGR SDT has explained in the White Paper it has developed, the DGR SDT has classified each of these standards as high-priority standards requiring applicability changes as soon as practicable.

Because each of the high-priority standards has recently been revised or is undergoing revision in another active standard development project, the DGR SDT has developed revisions to multiple versions of each standard to allow for different possibilities in the timing of regulatory approvals. Specifically, two of the three standards identified by the DGR SDT as high priority (PRC-004 and PRC-005) are being revised by other projects. NERC and the DGR SDT recognize that developing multiple versions of the same standard in different projects may be confusing; however, developing and balloting the recommended DGR applicability revisions separately from the technical changes that are ongoing in other active standard development projects provides flexibility in effectuating applicability revisions on an expedited timeline as needed to support implementation of the revised definition of the Bulk Electric System. The DGR project is being carefully coordinated with other active standard development projects with careful consideration of the period of time various versions of each standard may be in effect.

When DGR revisions are applied to a standard version that is not the last approved version of the standard or to a standard version that may be superseded by another version in active standard development outside the DGR project, the version is noted with "(X)" after it. For example, the DGR SDT is developing PRC-005-2(X), which proposes applicability changes to PRC-005-2, as well as PRC-005-3(X), which proposes applicability changes to PRC-005-3. Please note that NERC will apply at a later time the appropriate version numbers to standard versions containing an "X" suffix in order to effectively manage sequencing of version numbers in these projects.

PRC-004 DGR Applicability Modifications

(*Note that since PRC-004-3 is posted for a 45-day comment period and additional ballot through June 30, 2014, NERC is deferring posting DGR applicability recommendations on PRC-004 until after that ballot closes.)*

PRC-004-2.1a (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) is FERC-approved and has been enforceable since November 25, 2013. PRC-004-3 is in active standard development in Project 2010-05.1 and may supersede PRC-004-2.1a; however, until PRC-004-3 is completed, approved by applicable government authorities, and becomes enforceable, there may be a need for revisions to tailor the applicability of PRC-004-2.1a, which the DGR SDT intends to ballot as PRC-004-2.1a(X). The proposed implementation period for PRC-004-3 is 12 months.

PRC-004-3 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) is currently in active standard development in Project 2010-05.1 Protection System Misoperations. The DGR SDT and the Protection System Misoperations SDT are coordinating regarding changes to the applicability of PRC-004. The DGR

SDT intends to ballot proposed applicability revisions to PRC-004-3 as PRC-004-3(X). Depending on the timing of completion of Project 2010-05.1 relative to Project 2014-01, both PRC-004-2.1a(X) and PRC-004-3(X) may be needed.

PRC-005 DGR Applicability Modifications

PRC-005-2 (Protection System Maintenance): PRC-005-2 is FERC-approved and will become enforceable on April 1, 2015. PRC-005-2 has a 12-year phased-in implementation period and may be enforceable for a period of time before PRC-005-3 becomes enforceable after approval by the applicable government authorities. Therefore, the DGR SDT is balloting proposed revisions to the applicability of PRC-005-2 as PRC-005-2(X).

PRC-005-3 (Protection System and Automatic Reclosing Maintenance): PRC-005-3 was adopted by the NERC Board of Trustees (Board) on November 7, 2013 and filed with the applicable governmental authorities on February 14, 2014. Upon regulatory approval, PRC-005-3 will supersede PRC-005-2, and according to its proposed implementation plan, will continue the 12-year implementation period for components included in PRC-005-2. Therefore, the DGR SDT is balloting proposed revisions to the applicability of PRC-005-3 as PRC-005-3(X).

PRC-005-X (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance): PRC-005-X is currently in an active standards development project. A ballot for PRC-005-X concluded on June 3, 2014 but did not receive sufficient affirmative votes for approval. The PRC-005-X SDT will consider comments and, if needed, make revisions to the standard. Language to clarify the applicability of the requirements of PRC-005-X was agreed to by both SDTs, and is being balloted in the DGR project as PRC-005-X(X). Depending on the timing of the completion of the DGR project relative to Project 2007-17.3, NERC will determine the appropriate approach to filing applicability changes approved by balloters and adopted by the Board.

VAR-002 DGR Applicability Modifications

VAR-002-2b (Generator Operation for Maintaining Network Voltage Schedules) is FERC-approved and has been enforceable since July 1, 2013. A successor version, VAR-002-3, is pending regulatory approval and has a proposed implementation period of one quarter. Depending on the time of regulatory approvals of VAR-002-3, VAR-002-2b may remain in effect. Therefore, the DGR SDT is balloting proposed revisions to clarify the applicability of VAR-002-2b as VAR-002-2b(X).

VAR-002-3 (Generator Operation for Maintaining Network Voltage Schedules) was adopted by the Board on May 7, 2014 and filed with the applicable governmental authorities on June 10, 2014. No other version of VAR-002 is in active standard development outside the DGR project. Therefore, the DGR SDT is balloting proposed revisions to VAR-002-3 as VAR-002-4.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation		
Date Submitted:	10/1/2013		
SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
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. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard. **PRC-005-2** Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply. **FAC-008-3** For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information
Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels. **PRC-023-3/PRC-025-1** In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements. **PRC-004-2** There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above. **VAR-002-2** Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard. **General review of IROs, MODs, PRCs, TOPs** IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

Reliability Functions		
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Standards Announcement Reminder

Project 2014-01 Standards Applicability for Dispersed Generation Resources
VAR-002-2b(X) and VAR-002-4

Additional Ballots Now Open through October 16, 2014

Now Available

An additional ballot for two of the **Project 2014-01 Standards Applicability for Dispersed Generation Resources "high-priority" Reliability Standards (VAR-002-2b(X) and VAR-002-4)** as identified in the draft White Paper prepared by the Project 2014-01 standard drafting team is open through **8 p.m. Eastern on Thursday, October 16, 2014.**

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standards by clicking here.

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballots. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Sean Cavote.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
VAR-002-2b(X) and VAR-002-4

Formal Comment Period Now Open through October 16, 2014

Now Available

A 45-day formal comment period for two of the **Project 2014-01 Dispersed Generation Resources "high-priority" Reliability Standards (VAR-002-2b(X) and VAR-002-4)** as identified in the draft White Paper prepared by the Project 2014-01 drafting team is open through **8 p.m. Eastern on Thursday, October 16, 2014.**

Instructions for Commenting

Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot period for the standards will be conducted **October 7-16, 2014.**

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballots. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please case an abstention.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Sean Cavote, Standards Developer, or at 404-446-2560.

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Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
VAR-002-2b(X) and VAR-002-4

Formal Comment Period Now Open through October 16, 2014

Now Available

A 45-day formal comment period for two of the **Project 2014-01 Dispersed Generation Resources "high-priority" Reliability Standards (VAR-002-2b(X) and VAR-002-4)** as identified in the draft White Paper prepared by the Project 2014-01 drafting team is open through **8 p.m. Eastern on Thursday, October 16, 2014.**

Instructions for Commenting

Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot period for the standards will be conducted **October 7-16, 2014.**

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballots. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please case an abstention.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Sean Cavote, Standards Developer, or at 404-446-2560.

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404-446-2560 | www.nerc.com

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Resources
VAR-002-4 and VAR-002-2b(X)

Additional Ballot Results

Now Available

Additional ballots for **Project 2014-01 VAR-002-4 – Generator Operation for Maintaining Network Voltage Schedules and VAR-002-2b(X) – Generator Operation for Maintaining Network Voltage Schedules** concluded at **8 p.m. Eastern on Thursday, October 16, 2014**.

The standards achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot	Quorum /Approval
VAR-002-4	81.91% / 94.92%
VAR-002-2b(X)	82.12% / 94.37%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2014-01 VAR-002-4
Ballot Period:	10/7/2014 - 10/16/2014
Ballot Type:	Additional
Total # Votes:	317
Total Ballot Pool:	387
Quorum:	**81.91 % The Quorum has been reached**
Weighted Segment Vote:	94.92 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	103	1	59	0.922	5	0.078	0	17	22
2 - Segment 2	8	0.1	1	0.1	0	0	0	4	3
3 - Segment 3	85	1	57	0.934	4	0.066	0	15	9
4 - Segment 4	27	1	20	0.952	1	0.048	0	1	5
5 - Segment 5	93	1	59	0.937	4	0.063	0	9	21
6 - Segment 6	54	1	40	0.93	3	0.07	0	5	6
7 - Segment 7	3	0.2	2	0.2	0	0	0	0	1
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	8	0.7	7	0.7	0	0	0	0	1
Totals	**387**	**6.4**	**249**	**6.075**	**17**	**0.325**	**0**	**51**	**70**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise

				Group)
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple		
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle		
1	Omaha Public Power District	Doug Peterchuck		
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	COMMENT RECEIVED
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox		

2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan		
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
				SUPPORTS THIRD PARTY

3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENTS - (SPP Group Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		

5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin		

5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SP{P Comments)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein	Affirmative	
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	

6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-01 VAR-002-2b(X)
Ballot Period:	10/7/2014 - 10/16/2014
Ballot Type:	Additional
Total # Votes:	317
Total Ballot Pool:	386
Quorum:	**82.12 % The Quorum has been reached**
Weighted Segment Vote:	94.37 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	103	1	57	0.919	5	0.081	0	19	22
2 - Segment 2	8	0.1	1	0.1	0	0	0	4	3
3 - Segment 3	85	1	56	0.933	4	0.067	0	16	9
4 - Segment 4	27	1	20	0.952	1	0.048	0	2	4
5 - Segment 5	92	1	57	0.934	4	0.066	0	10	21
6 - Segment 6	54	1	39	0.907	4	0.093	0	5	6
7 - Segment 7	3	0.2	2	0.2	0	0	0	0	1
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	8	0.6	6	0.6	0	0	0	1	1
Totals	**386**	**6.3**	**242**	**5.945**	**18**	**0.355**	**0**	**57**	**69**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise

				Group)
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple		
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle		
1	Omaha Public Power District	Doug Peterchuck		
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	COMMENT RECEIVED
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox		

2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Abstain	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan		
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
				SUPPORTS THIRD PARTY

3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENTS - (SPP Group Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		

5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin		
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	

5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein	Abstain	
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	

6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Individual or group. (17 Responses)
Name (9 Responses)
Organization (9 Responses)
Group Name (8 Responses)
Lead Contact (8 Responses)
Question 1 (15 Responses)
Question 1 Comments (17 Responses)
Question 2 (17 Responses)
Question 2 Comments (17 Responses)

Group
DTE Electric Co.
Kathleen Black
Yes
No
Group
Northeast Power Coordinating Council
Guy Zito
Yes
For VAR-002-4, the Drafting Team should consider adding start-up and shutdown from footnotes 1 and 2 to the NERC Glossary. For footnote 2 on page 5 suggest replacing “prepared” with “intended”. Because the Rationale Boxes stay with the standard after approval, the Drafting Team should consider moving the information in the footnotes to the appropriate Rationale Boxes, and deleting the footnotes.
Group
Arizona Public Service Co
Janet Smith
Yes
No
Individual
Thomas Foltz
American Electric Power
Yes
No
Individual
John Seelke
Public Service Enterprise Group
No
VAR-002-2b(X) The bullet added to subpart 3.1 exempts ALL I4 generators from reporting on their VAR capability status. Not only is this discriminatory to I2 generators, it omits key data for TOPs required to maintain voltage via VAR supply. If the bullet was changed so that changes in AGGREGATE VAR capability for a facility that contains I4 generators was reported, that would be OK;

but it is unacceptable as written. Footnote 5 in R4 is also unacceptable for two reasons. First, it is discriminatory to I2 generators. Second, the modeling of ALL transformers, which consume VARS, will result in less ability for TOPs to correctly model their VAR supply. We also point out that I4 generators are already obligated to comply with the standard without the proposed changes, and no reliability argument has been offered by the SDT that validates the changes proposed. VAR-002-4 The same comments made for VAR-002-2b(X) apply, except that the bullet is in R4 and footnote 5 is in R5. While this standard is not effective, its predecessor, as discussed previously, does require I4 generators to meet the same requirements. No reliability argument has been provided by the SDT to support the change.
Yes
Describe the reliability impacts of proposed changes
Individual
Heather Bowden
EDP Renewables North America LLC
Yes
Yes
Individual
Timothy Brown
Idaho Power
Yes
No
Individual
Michelle D'Antuono
Ingleside Cogeneration LP/Occidental Energy Ventures Corp.
Yes
Occidental Energy Ventures Corp. agrees that the scope of R3.1 and R4 has been appropriately modified to capture the applicable AVRs, PSSs, and transformers located within a dispersed generation facility. There is no good reason to apply BES-level voltage and reactive requirements to individual windmills or solar panels – unless somehow a significant aggregation point is affected. This is unlikely to be the case most of the time, and if every minimal incident is subject to VAR-002-4, both the relay owner and CEA community could be overwhelmed.
No
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
Yes
VAR-002-4 1)Requirements R4 and R5: Texas Reliability Entity, Inc. (Texas RE) requests the SDT make a change to either R4 or R5 regarding placement of exclusion language for consistency. In Requirement R4 the exclusion statement is a bulleted item within the requirement text. In Requirement R5 the exclusion statement is a footnote at the bottom of the page. Texas RE suggests that moving the exclusion language in the requirement language of Requirement R5 is preferable to moving Requirement R4 exclusion language to a footnote. 2)Requirement R5 VSLs: Texas RE requests the SDT consider changing Requirement R5 VSL Levels as follows: Moderate "…one of the types of data…" High "…two of the types of data…" Severe "…all of the types of data…" Changing the VSL language in this manner is consistent with VAR-002-2b(x), Requirement R4 VSL levels. VAR-

002-2b(X) Texas RE suggests a minor change to the Requirement R4 Severe VSL: replace the word “any” with “all” in the first statement. As written, it would appear that a responsible entity failing to provide any one of the types of data would result in a severe VSL instead of the failure to provide all of the types of data. This change would result in the following Severe VSL language: “The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner all of the types of data as specified in R4.1.1 and R 4.1.2 and 4.1.3 and 4.1.4…”
Group
Colorado Springs Utilities
Kaleb Brimhall
No
We Support the Comments of - Public Service Enterprise Group (PSEG).
Yes
We Support the Comments of - Public Service Enterprise Group (PSEG).
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
No
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
Yes
Group
Dominion Resources, Inc.
Randi Heise
Yes
Dominion supports the revisions to R4 and R5 in support of clarity.
Yes
Comments: Dominion believes there should either be a variance in recognition of the WECC regional standards VAR-002-WECC-1 and VAR-501-WECC-1 in this standard or an explanation as to how this continent-wide standard is or is not impacted by those regional standards given all contained requirements relative to actions required to be taken by the Generator Operator when the AVR or PSS is out of service. We suggest the SDT review the current style guide regarding whether to use sub-parts (3.1, 4.1, etc) as opposed to using bullets. Having sub-parts identified make identification of information to communicate.
Individual
Spencer Tacke
Modesto Irrigation District
No
For both VAR-002 proposed modifications, I don’t think we should state non-applicability of the Standard for dispersed generation resources identified through Inclusion I4 of the BES definition, as the new addition of “Rationale for Footnote 5” erroneously states (i.e., “as they are not used to improve voltage performance at the point of interconnection”, which is simply not true). Some technical reasons for including the smaller generating units are as follows: WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller

size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed. Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2018. Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
No
Group
SPP Standards Review Group
Robert Rhodes
No
Description of Current Draft – Language in this section indicates that VAR-002-3 '...was adopted by the NERC Board of Trustees in May 2014 and is pending regulatory approval'. Shouldn't this be revised to indicate that FERC has now approved VAR-002-3 and it will become effective on October 1, 2014? A similar statement is included in the Rationale Box appearing alongside the Introduction. R3 – Shouldn't the exception that is being proposed for Requirement R4, also be applied to Requirement R3? Otherwise, the Generator Operator will be required to report status changes for AVRs or other voltage controlling devices for each individual generating unit of a dispersed power producing resource. R4 – In the first line of the bullet under Requirement R4, insert 'Requirement' between 'in' and 'R4'. Rationale Box for Exclusion in Requirement R4 – Replace 'real time' with the officially recognized term 'Real-time' in the last line in the Rationale Box. M5 – To make Measure M5 consistent with the language in Requirement R5, delete 'transformers' following 'its step-up'.
No
Group
ACES Standards Collaborators
Jason Marshall
Yes
We agree with the changes.
Yes
The language adopted in the bullet under Part 3.1 of VAR-002-2b(X) is inconsistent with the August 10, 2009 informational filing NERC submitted to FERC regarding how NERC would begin using a new approach to assign VRFs and VSLs to the main requirement only. In this filing, NERC stated that they would no longer refer to "components" or "sub-parts" of requirements as sub-requirements. Rather, they would be numbered or bulleted lists. Thus, the Requirement R3.1 reference in the bullet under Part 3.1 is inconsistent and should be labeled as Part 3.1.
Individual
Scott Berry
Indiana Municipal Power Agency
Yes
IMPA does not agree with the deletion of the rationales for each requirement on pages 11 and 12. These rationales are used for the previous version of the standard and are still needed in the standard. The additions made by the dispersed generation SDT should not have changed the basis for these rationales. IMPA is fine with adding to them but not deleting all of them.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

This version of PRC-005 contains revisions to the applicability of the Standard intended to clarify application of its Requirements to Bulk Electric System dispersed power producing resources. PRC-005-3, a subsequent version of PRC-005, has been adopted by the NERC Board of Trustees and is pending regulatory approval. Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-005-2(X) for balloting purposes, may be filed for regulatory approval. The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is concurrently making technical revisions to PRC-005 in Project 2007-17.3 to address FERC directives. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-005 to dispersed power-producing resources.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. Title: **Protection System Maintenance**

2. Number: PRC-005- X

3. Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems 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 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 Special Protection System (SPS) for BES reliability.

> The only revisions made to this version of PRC-005 are revisions to section 4.2, 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.
>
> This version is labeled PRC-005-2(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-005 are in development to reflect the fact that applicability changes need apply for versions of the standard that are approved (PRC-005-2), pending regulatory approval (PRC-005-3), and in development in Project 2007-17.3. Depending on the timing of approvals of other versions, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:

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 for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems 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.

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

4.2.6 Protection Systems 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 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 100 kV or above.

Rationale for 4.2.6: Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

5. **Effective Date:** See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[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 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 Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System 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, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System 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 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, and Table 3. (Part 1.2)

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.

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 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.

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 Protection System Maintenance Program for the Protection System 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.

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.

D. 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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, 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.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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) OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)	The responsible 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)	The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				• Annually perform maintenance on the greater of 5% of the segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15	The responsible entity failed to undertake efforts to correct greater

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	fewer identified Unresolved Maintenance Issues.	identified Unresolved Maintenance Issues.	identified Unresolved Maintenance Issues.	than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	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.	
2	December 19, 2013	FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014.	
TBD (balloted as 2(X)	TBD	Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[1]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[1] 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**[1]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack
	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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 **Component Type - Control Circuitry Associated With Protective Functions** **Excluding distributed UFLS and distributed UVLS (see Table 3)** **Note:** Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS.	12 calendar years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5 and Table 3, 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 and Table 3 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	Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

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 of the Protection System Component population, 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 and Table 3 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 Protection System 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.
5. If the Components in a Protection System 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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

This version of PRC-005 contains revisions to the applicability of the Standard intended to clarify application of its Requirements to Bulk Electric System dispersed power producing resources. PRC-005-3, a subsequent version of PRC-005, has been adopted by the NERC Board of Trustees and is pending regulatory approval. Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-005-2(X) for balloting purposes, may be filed for regulatory approval. The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is concurrently making technical revisions to PRC-005 in Project 2007-17.3 to address FERC directives. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-005 to dispersed power-producing resources.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Maintenance**

2. **Number:** PRC-005- X

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems 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 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 Special Protection System (SPS) for BES reliability.

   4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:

   4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

> The only revisions made to this version of PRC-005 are revisions to section 4.2, 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~~ power ~~Producing~~ producing ~~Resources~~resources.
>
> This version is labeled PRC-005-2(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-005 are in development to reflect the fact that applicability changes need apply for versions of the standard that are approved (PRC-005-2), pending regulatory approval (PRC-005-3), and in development in Project 2007-17.3. Depending on the timing of approvals of other versions, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is

> **Rationale for 4.2.5:** In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems 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 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 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 100 kV or above.

Rationale for 4.2.6: Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

5. Effective Date: See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[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 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 Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System 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, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System 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 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, and Table 3. (Part 1.2)

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.

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 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.

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 Protection System Maintenance Program for the Protection System 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.

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.

D. 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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, 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.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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) OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)	The responsible 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)	The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				• Annually perform maintenance on the greater of 5% of the segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Maintenance Issues.	identified Unresolved Maintenance Issues.	identified Unresolved Maintenance Issues.	Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	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.	
2	December 19, 2013	FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014.	
TBD (balloted as 2(X)	TBD	Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[1]	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[1] 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[1]**	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack
	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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) **Note:** Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS.	12 calendar years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5 and Table 3, 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 and Table 3 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	Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.
Voltage and/or current sensing devices associated with UFLS or UVLS	12 calendar	Verify that current and/or voltage signal values are provided to

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
systems.	years	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.

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 of the Protection System Component population, 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 and Table 3 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 Protection System 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.
5. If the Components in a Protection System 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.

A. Introduction

1. Title: **Protection System Maintenance**

2. Number: PRC-005-~~2~~ X

3. Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems 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 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 Special Protection System (SPS) for BES reliability.

4.2.5 Protection Systems for the following BES generator Facilities ~~that are part~~for generators not identified through Inclusion I4 of the BES~~,~~ ~~including~~ definition:

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 for generator step-up transformers for generators that are part of the BES.

~~**4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind farms to the BES).~~

~~**4.2.5.4**~~**4.2.5.3** Protection Systems 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.

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

4.2.6 Protection Systems 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 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 100 kV or above.

Rationale for 4.2.6: Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

5. Effective Date: See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[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 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.

~~***Component Type*** *– Any one of the five specific elements of the Protection System definition.*~~

1.2. Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.

~~**Component** *– A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.*~~

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System 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, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~***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.*~~

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System 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 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, and Table 3. (Part 1.2)

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.

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 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.

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 Protection System Maintenance Program for the Protection System 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.

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.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~Regional Entity~~

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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, 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.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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) OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)	The responsible 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)	The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). ~~OR~~ ~~The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)~~
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to:

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				• Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	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.	
2	December 19, 2013	FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014.	
~~2~~TBD (balloted as 2(X))	~~May 7, 2014~~TBD	~~Adopted by the NERC Board of Trustees to modify VSLs for Requirement R1.~~Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources
~~2~~	~~August 25, 2014~~	~~FERC issued letter order to modify VSLs for Requirement R1.~~	

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[1]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[1] 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**[1]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack
	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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) **Note:** Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS.	12 calendar years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5 and Table 3, 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 and Table 3 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	Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

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 of the Protection System Component population, 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 and Table 3 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.

~~**Segment** – *Protection Systems or 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.*~~

~~**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 and Table 3 which requires corrective action, or a 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 configuration errors, or Protection System application errors are not included in Countable Events.*~~

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Protection System 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.
5. If the Components in a Protection System 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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01, Standards Applicability for Dispersed Generation Resources Standards Drafting Team (DGR SDT) is posting proposed applicability changes to PRC-005-3 for comment and ballot. This draft contains the DGR SDT's recommended changes within the standard. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-005 to dispersed power-producing resources.

In a parallel effort, the Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) has posted draft 1 of PRC-005-X for a 45-day comment period, and ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System and Automatic Reclosing Maintenance**

2. **Number:** PRC-005-3(X)

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing 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 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 Special Protection System (SPS) for BES reliability.

The only revisions made to this version of PRC-005 are revisions to section 4.2, 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.

This version is labeled PRC-005-3(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-005 are in development to reflect the fact that applicability changes need apply for versions of the standard that are approved (PRC-005-2), pending regulatory approval (PRC-005-3), and in development in Project 2007-17.3.

4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:

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 for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems 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.

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

4.2.6 Protection Systems 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 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 100 kV or above.

4.2.7 Automatic Reclosing[1], including:

Rationale for 4.2.6: Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

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[1] 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 BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

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.

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 SPS specified in Section 4.2.4.

5. Effective Date: See Implementation Plan.

6. Definitions Used in this Standard: The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing 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 – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

Component – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

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, and Tables 4-1 through 4-2 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 or Automatic Reclosing configuration or application errors are not included in Countable Events.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[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 and Automatic Reclosing 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 and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing 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, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing 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 and Automatic Reclosing 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, and Table 4-1 through 4-2. (Part 1.2)

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.

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 and Automatic Reclosing 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.

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 Protection System Maintenance Program for the Protection System and Automatic Reclosing 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.

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.

D. 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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, 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.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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) OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)	The responsible 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)	The responsible 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). OR The responsible 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, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible 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).
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by 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
2	October 17, 2013	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	
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.
TBD (balloted as 2(X)	TBD	Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[2]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[2] 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[2]**	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, 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, and Tables 4-1 through 4-2 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	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	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 SPS 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 Relays that ARE an Integral Part of an SPS		
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 SPS (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 SPS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the SPS.
Control circuitry associated with Automatic Reclosing that is an integral part of an SPS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

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, and Tables 4-1 through 4-2 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.
5. 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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01, Standards Applicability for Dispersed Generation Resources Standards Drafting Team (DGR SDT) is posting proposed applicability changes to PRC-005-3 for comment and ballot. This draft contains the DGR SDT's recommended changes within the standard. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-005 to dispersed power-producing resources.

In a parallel effort, the Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) has posted draft 1 of PRC-005-X for a 45-day comment period, and ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June – July 2014
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	August – September 2014
Final ballot	October 2014
BOT adoption	November 2014

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System and Automatic Reclosing Maintenance**
2. **Number:** PRC-005-3(X)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing 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 that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

The only revisions made to this version of PRC-005 are revisions to section 4.2, 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 p~~P~~ower p~~P~~roducing r~~R~~esources.

This version is labeled PRC-005-3(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-005 are in development to reflect the fact that applicability changes need apply for versions of the standard that are approved (PRC-005-2), pending regulatory approval (PRC-005-3), and in development in Project 2007-17.3.

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 Special Protection System (SPS) for BES reliability.

4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:

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 for generator step-up

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

transformers for generators that are part of the BES.

4.2.5.3 Protection Systems 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 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 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 100 kV or above.

Rationale for 4.2.6: Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

4.2.7 Automatic Reclosing[1], 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.

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.~~6~~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 SPS specified in Section 4.2.4.

5. Effective Date: See Implementation Plan.

[1] Automatic Reclosing addressed in Section 4.2.7~~6~~.1 and 4.2.7~~6~~.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 BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

6. Definitions Used in this Standard: The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing 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 – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

Component – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

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, and Tables 4-1 through 4-2 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 or Automatic Reclosing configuration or application errors are not included in Countable Events.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[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 and Automatic Reclosing 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 and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing 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, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing 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 and Automatic Reclosing 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, and Table 4-1 through 4-2. (Part 1.2)

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.

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 and Automatic Reclosing 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.

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 Protection System Maintenance Program for the Protection System and Automatic Reclosing 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.

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.

D. 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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, 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.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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) OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)	The responsible 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)	The responsible 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). OR The responsible 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, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible 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).
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	their performance-based PSMP.	with their performance-based PSMP.	their performance-based PSMP.	with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by 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
2	October 17, 2013	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	
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.
TBD (balloted as 2(X)	TBD	Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[2]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[2] 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**[2]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f)
Exclusions for Protection System Station dc Supply Monitoring Devices and Systems

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, 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, and Tables 4-1 through 4-2 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	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	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 SPS 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 Relays that ARE an Integral Part of an SPS		
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 SPS (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 SPS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the SPS.
Control circuitry associated with Automatic Reclosing that is an integral part of an SPS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

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, and Tables 4-1 through 4-2 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.
5. 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.

A. Introduction

1. **Title:** **Protection System and Automatic Reclosing Maintenance**

2. **Number:** PRC-005-3(X)

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing 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 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 Special Protection System (SPS) for BES reliability.

   4.2.5 Protection Systems for the following BES generator Facilities ~~that are part~~for generators not identified through Inclusion I4 of the BES~~, including:~~ definition:

   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 for generator step-up transformers for generators that are part of the BES.

The only revisions made to this version of PRC-005 are revisions to section 4.2, 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.

This version is labeled PRC-005-3(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-005 are in development to reflect the fact that applicability changes need apply for versions of the standard that are approved (PRC-005-2), pending regulatory approval (PRC-005-3), and in development in Project 2007-17.3.

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

~~4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).~~

~~4.2.5.4~~4.2.5.3 Protection Systems 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 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 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 100 kV or above.

Rationale for 4.2.6: Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

~~4.2.6~~4.2.7 Automatic Reclosing[1], including:

~~4.2.6.1~~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.

~~4.2.6.2~~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.~~6~~7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

[1] Automatic Reclosing addressed in Section 4.2.~~6~~7.1 and 4.2.~~6~~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 BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

~~4.2.6.3~~4.2.7.3 Automatic Reclosing applied as an integral part of an SPS specified in Section 4.2.4.

5. Effective Date: See Implementation Plan.

6. Definitions Used in this Standard: The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing 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 – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

Component – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

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, and Tables 4-1 through 4-2 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 or Automatic Reclosing configuration or application errors are not included in Countable Events.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[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 and Automatic Reclosing 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 and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

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]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing 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, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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 and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing 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 and Automatic Reclosing 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, and Table 4-1 through 4-2. (Part 1.2)

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.

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 and Automatic Reclosing 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.

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 Protection System Maintenance Program for the Protection System and Automatic Reclosing 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.

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.

D. 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. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. 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 Protection System Maintenance Program, 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 Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, 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.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible 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) OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)	The responsible 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)	The responsible 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). OR The responsible 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, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible 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).
R2	The responsible 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 responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible 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, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

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.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by 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
2	October 17, 2013	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	
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.
TBD (balloted as 2(X)	TBD	Standard revised in Project 2014-01	Applicability section revised to clarify application of Requirements to BES dispersed power producing resources

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[2]	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • 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. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[2] 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**[2]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). • Alarming for change of settings (See Table 2).	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: • 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) • 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).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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 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 SPS, 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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 • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

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 SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
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 SPS, 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 **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	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 SPS, 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: • Station dc supply voltage Inspect: • For unintentional grounds
	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 SPS, 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 SPS, 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.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
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 SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
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 SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, 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, and Tables 4-1 through 4-2 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	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • 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. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • 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). Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	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 SPS 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 Relays that ARE an Integral Part of an SPS		
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 SPS (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 SPS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the SPS.
Control circuitry associated with Automatic Reclosing that is an integral part of an SPS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

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, and Tables 4-1 through 4-2 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.
5. 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.

Implementation Plan

Project 2014-01 Standards Applicability for Dispersed Power Producing Resources
PRC-005-2(X)

The standard numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to BOT adoption.

Standards Involved
Approval:

- PRC-005-2(X) – Protection System Maintenance

Retirement:

- PRC-005-2 – Protection System Maintenance

Prerequisite Approvals:
N/A

Background:
In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

Reliability Standard PRC-005-2, with its associated Implementation Plan, was adopted by the NERC Board of Trustees on November 7, 2012. The SDT has revised the applicability section of PRC-005-2 to align with the revised definition of "Bulk Electric System" in the event that this version of PRC-005 is mandatory and enforceable on the effective date of the revised definition of "Bulk Electric System."

General Considerations:
PRC-005-2(X) is proposed for approval to align the applicability section of PRC-005-2 with the revised definition of "Bulk Electric System." PRC-005-2 may already be retired pursuant to an implementation plan of a successor version of PRC-005 by the time the revised definition of "Bulk Electric System" becomes effective. If this occurs, PRC-005-2(X) will not go into effect.

Effective Date

PRC-005-2(X) shall become effective on the later of the effective date of the revised definition of Bulk Electric System or the first day following the effective date of PRC-005-2.

Retirement of Existing Standards:

PRC-005-2 shall be retired at midnight of the day immediately prior to the effective date of PRC-005-2(X) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

All aspects of the Implementation Plan for PRC-005-2 will remain applicable to PRC-005-2(X) and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-005-2 is available here.

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Implementation Plan

Project 2014-01 Standards Applicability for Dispersed Power Producing Resources
PRC-005-3(X)

The standard numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to BOT adoption.

Standards Involved

Approval:

- PRC-005-3(X) – Protection System and Automatic Reclosing Maintenance

Retirement:

- PRC-005-2(X) – Protection System Maintenance
- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Prerequisite Approvals

N/A

Background

In light of the adoption of a revised “Bulk Electric System” definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised “Bulk Electric System” definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

Reliability Standard PRC-005-3, with its associated Implementation Plan, was adopted by the NERC Board of Trustees on November 7, 2013. The SDT has revised the applicability section of PRC-005-3 to align with the revised definition of “Bulk Electric System” in the event that this version of PRC-005 is mandatory and enforceable on the effective date of the revised definition of “Bulk Electric System.”

General Considerations

PRC-005-3(X) is proposed for approval to align the applicability section of PRC-005-3 with the revised definition of “Bulk Electric System.” PRC-005-3 may already be retired pursuant to an Implementation Plan of a successor version of PRC-005 by the time the revised definition of “Bulk Electric System” becomes effective. If this occurs, PRC-005-3(X) will not go into effect.

Effective Date

PRC-005-3(X) shall become effective on the later of the effective date of the revised definition of Bulk Electric System or the first day following the effective date of PRC-005-3.

Retirement of Existing Standards

PRC-005-3 shall be retired at midnight of the day immediately prior to the effective date of PRC-005-3(X) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

PRC-005-3(X) only modifies the applicability for PRC-005-3. All aspects of the Implementation Plan for PRC-005-3 will remain applicable to PRC-005-3(X) and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-005-3 is available here.

Project 2014-01 Dispersed Generation Resources

DRAFT Plan for Standards Drafting Team (SDT) Coordination and Balloting Multiple Versions of Standards | June 12, 2014

Background

Pursuant to the Standards Authorization Request for this project posted on November 20, 2014, the Project 2014-01 Dispersed Generation Resources (DGR) SDT proposes to modify PRC-004-2.1a, PRC-004-3, PRC-005-2, PRC-005-3, PRC-005-X, VAR-002-2b, and VAR-002-3 to account for the unique characteristics of dispersed power producing resources. As the DGR SDT has explained in the White Paper it has developed, the DGR SDT has classified each of these standards as high-priority standards requiring applicability changes as soon as practicable.

Because each of the high-priority standards has recently been revised or is undergoing revision in another active standard development project, the DGR SDT has developed revisions to multiple versions of each standard to allow for different possibilities in the timing of regulatory approvals. Specifically, two of the three standards identified by the DGR SDT as high priority (PRC-004 and PRC-005) are being revised by other projects. NERC and the DGR SDT recognize that developing multiple versions of the same standard in different projects may be confusing; however, developing and balloting the recommended DGR applicability revisions separately from the technical changes that are ongoing in other active standard development projects provides flexibility in effectuating applicability revisions on an expedited timeline as needed to support implementation of the revised definition of the Bulk Electric System. The DGR project is being carefully coordinated with other active standard development projects with careful consideration of the period of time various versions of each standard may be in effect.

When DGR revisions are applied to a standard version that is not the last approved version of the standard or to a standard version that may be superseded by another version in active standard development outside the DGR project, the version is noted with "(X)" after it. For example, the DGR SDT is developing PRC-005-2(X), which proposes applicability changes to PRC-005-2, as well as PRC-005-3(X), which proposes applicability changes to PRC-005-3. Please note that NERC will apply at a later time the appropriate version numbers to standard versions containing an "X" suffix in order to effectively manage sequencing of version numbers in these projects.

PRC-004 DGR Applicability Modifications

(*Note that since PRC-004-3 is posted for a 45-day comment period and additional ballot through June 30, 2014, NERC is deferring posting DGR applicability recommendations on PRC-004 until after that ballot closes.)*

PRC-004-2.1a (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) is FERC-approved and has been enforceable since November 25, 2013. PRC-004-3 is in active standard development in Project 2010-05.1 and may supersede PRC-004-2.1a; however, until PRC-004-3 is completed, approved by applicable government authorities, and becomes enforceable, there may be a need for revisions to tailor the applicability of PRC-004-2.1a, which the DGR SDT intends to ballot as PRC-004-2.1a(X). The proposed implementation period for PRC-004-3 is 12 months.

PRC-004-3 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) is currently in active standard development in Project 2010-05.1 Protection System Misoperations. The DGR SDT and the Protection System Misoperations SDT are coordinating regarding changes to the applicability of PRC-004. The DGR

SDT intends to ballot proposed applicability revisions to PRC-004-3 as PRC-004-3(X). Depending on the timing of completion of Project 2010-05.1 relative to Project 2014-01, both PRC-004-2.1a(X) and PRC-004-3(X) may be needed.

PRC-005 DGR Applicability Modifications

PRC-005-2 (Protection System Maintenance): PRC-005-2 is FERC-approved and will become enforceable on April 1, 2015. PRC-005-2 has a 12-year phased-in implementation period and may be enforceable for a period of time before PRC-005-3 becomes enforceable after approval by the applicable government authorities. Therefore, the DGR SDT is balloting proposed revisions to the applicability of PRC-005-2 as PRC-005-2(X).

PRC-005-3 (Protection System and Automatic Reclosing Maintenance): PRC-005-3 was adopted by the NERC Board of Trustees (Board) on November 7, 2013 and filed with the applicable governmental authorities on February 14, 2014. Upon regulatory approval, PRC-005-3 will supersede PRC-005-2, and according to its proposed implementation plan, will continue the 12-year implementation period for components included in PRC-005-2. Therefore, the DGR SDT is balloting proposed revisions to the applicability of PRC-005-3 as PRC-005-3(X).

PRC-005-X (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance): PRC-005-X is currently in an active standards development project. A ballot for PRC-005-X concluded on June 3, 2014 but did not receive sufficient affirmative votes for approval. The PRC-005-X SDT will consider comments and, if needed, make revisions to the standard. Language to clarify the applicability of the requirements of PRC-005-X was agreed to by both SDTs, and is being balloted in the DGR project as PRC-005-X(X). Depending on the timing of the completion of the DGR project relative to Project 2007-17.3, NERC will determine the appropriate approach to filing applicability changes approved by balloters and adopted by the Board.

VAR-002 DGR Applicability Modifications

VAR-002-2b (Generator Operation for Maintaining Network Voltage Schedules) is FERC-approved and has been enforceable since July 1, 2013. A successor version, VAR-002-3, is pending regulatory approval and has a proposed implementation period of one quarter. Depending on the time of regulatory approvals of VAR-002-3, VAR-002-2b may remain in effect. Therefore, the DGR SDT is balloting proposed revisions to clarify the applicability of VAR-002-2b as VAR-002-2b(X).

VAR-002-3 (Generator Operation for Maintaining Network Voltage Schedules) was adopted by the Board on May 7, 2014 and filed with the applicable governmental authorities on June 10, 2014. No other version of VAR-002 is in active standard development outside the DGR project. Therefore, the DGR SDT is balloting proposed revisions to VAR-002-3 as VAR-002-4.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation		
Date Submitted:	10/1/2013		
SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
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. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard.

PRC-005-2

Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply.

FAC-008-3

For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

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Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels. **PRC-023-3/PRC-025-1** In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements. **PRC-004-2** There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above. **VAR-002-2** Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard. **General review of IROs, MODs, PRCs, TOPs** IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

Reliability Functions		
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2014-01 Applicability for Dispersed Generation Resources Standards
PRC-005-2(X) and PRC-005-3(X)

Final Ballots Now Open through September 5, 2014

Now Available

Final ballots for **Project 2014-01 Dispersed Generation Resources Reliability Standards, (PRC-005-2(X) and PRC-005-3(X))** are open through **8 p.m. Eastern on Friday, September 5, 2014.**

Background information for this project can be found on the project page.

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standards by clicking here.

Next Steps

Voting results for the standards will be posted and announced after the ballot window closes. If approved, they will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Sean Cavote,
Standards Developer, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE

Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2014-01 Applicability for Dispersed Resources Standards
PRC-005-2(X) and PRC-005-3(X)

Final Ballot Results

Now Available

Final ballots for two **Project 2014-01 Dispersed Generation Resources Reliability Standards, (PRC-005-2(X) and PRC-005-3(X))** concluded at **8 p.m. Eastern on Friday, September 5, 2014**.

The standards achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

	Ballot Results
	Quorum /Approval
PRC-005-2(X)	85.32% / 95.35%
PRC-005-3(X)	86.01% / 95.86%

Background information for this project can be found on the project page.

Next Steps
The standards will be submitted to the NERC Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2014-01 PRC-005-2(X)
Ballot Period:	8/27/2014 - 9/5/2014
Ballot Type:	Final
Total # Votes:	337
Total Ballot Pool:	395
Quorum:	**85.32 % The Quorum has been reached**
Weighted Segment Vote:	95.35 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	69	0.958	3	0.042	0	18	15
2 - Segment 2	8	0.3	3	0.3	0	0	0	3	2
3 - Segment 3	89	1	60	0.952	3	0.048	0	15	11
4 - Segment 4	29	1	20	0.909	2	0.091	0	4	3
5 - Segment 5	93	1	60	0.952	3	0.048	0	13	17
6 - Segment 6	54	1	38	0.927	3	0.073	0	7	6
7 - Segment 7	3	0.1	1	0.1	0	0	0	0	2
8 - Segment 8	4	0.4	4	0.4	0	0	0	0	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	8	0.6	6	0.6	0	0	0	1	1
Totals	**395**	**6.5**	**262**	**6.198**	**14**	**0.302**	**0**	**61**	**58**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson		
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	

1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	

3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker		
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	

3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith		
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	

5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Renewable Power	Marcus Ellis		
5	Dominion Resources, Inc.	Mike Garton	Negative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden	Negative	COMMENT RECEIVED
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	

5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	

6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

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Ballot Results	
Ballot Name:	Project 2014-01 PRC-005-3(X)
Ballot Period:	8/27/2014 - 9/5/2014
Ballot Type:	Final
Total # Votes:	338
Total Ballot Pool:	393
Quorum:	**86.01 % The Quorum has been reached**
Weighted Segment Vote:	95.86 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	69	0.945	4	0.055	0	18	14
2 - Segment 2	8	0.3	3	0.3	0	0	0	3	2
3 - Segment 3	88	1	60	0.952	3	0.048	0	15	10
4 - Segment 4	29	1	21	0.955	1	0.045	0	4	3
5 - Segment 5	92	1	60	0.952	3	0.048	0	13	16
6 - Segment 6	54	1	38	0.927	3	0.073	0	7	6
7 - Segment 7	3	0.1	1	0.1	0	0	0	0	2
8 - Segment 8	4	0.4	4	0.4	0	0	0	0	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	8	0.6	6	0.6	0	0	0	1	1
Totals	**393**	**6.5**	**263**	**6.231**	**14**	**0.269**	**0**	**61**	**55**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson		
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	

1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	

3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker		
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	

3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		

5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden	Negative	COMMENT RECEIVED
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	

5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	

6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. A subsequent version of PRC-004, i.e., PRC-004-3, also is under active standard development. Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-004-2.1a(X) for balloting purposes, may be filed for regulatory approval. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	September – October 2014
Final ballot	October 2014
BOT adoption	November 2015

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1a(X)
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
   - **4.1.** Transmission Owner.
   - **4.2.** Distribution Provider that owns a transmission Protection System.
   - **4.3.** Generator Owner.
5. **Effective Date:** See the implementation plan for this Standard.

Rationale for Introduction: The only revisions made to this version of PRC-004-2.1a(X) are revisions to Requirements R2 and R3 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.

This version is labeled PRC-004-2.1a(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-004 have been in development. The 'X' designation reflects the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. Depending on the timing of approvals of other versions and other factors, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

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, Requirement R2 and Requirement R3 reflect the threshold consistent with the revised BES definition. See paragraph 20 of FERC Order Approving Revised Definition in Docket No. RD14-2-000. The intent of Requirement R2 and Requirement R3 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

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. 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. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the Board of Trustees	
1a	September 26,	FERC Order issued approving the interpretation	

	2011	of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
TBD (balloted as 2.1a(X))	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of Requirements to BES dispersed power producing resources

Appendix 1[1]

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. A subsequent version of PRC-004, i.e., PRC-004-3, also is under active standard development. Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-004-2.1a(X) for balloting purposes, may be filed for regulatory approval. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	September – October 2014
Final ballot	October 2014
BOT adoption	November 2015

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1a(X)
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
   - **4.1.** Transmission Owner.
   - **4.2.** Distribution Provider that owns a transmission Protection System.
   - **4.3.** Generator Owner.
5. ~~**(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.~~ **Effective Date:** See the implementation plan for this Standard.

Rationale for Introduction: The only revisions made to this version of PRC-004-2.1a(X) are revisions to Requirements R2 and R3 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.

This version is labeled PRC-004-2.1a(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-004 have been in development. The 'X' designation reflects the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. Depending on the timing of approvals of other versions and other factors, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

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, Requirement R2 and Requirement R3 reflect the threshold consistent with the revised BES definition. See paragraph 20 of FERC Order Approving Revised Definition in Docket No. RD14-2-000. The intent of Requirement R2 and Requirement R3 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

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~Regional Entity.~~

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. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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.	01/20/06

		Changed "Timeframe" to "Time Frame" in item D, 1.2.	
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
TBD (balloted as 2.1a(X))	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of Requirements to BES dispersed power producing resources

Appendix 1[1]

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. A subsequent version of PRC-004, i.e., PRC-004-3, also is under active standard development. Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-004-2.1a(X) for balloting purposes, may be filed for regulatory approval. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
~~45-day Formal Comment Period with Initial Ballot~~	~~July – August 2014~~
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	September – October 2014
Final ballot	~~November~~ October 2014
BOT adoption	~~February 2015~~November 2015

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1a(X)
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
   4.1. Transmission Owner.
   4.2. Distribution Provider that owns a transmission Protection System.
   4.3. Generator Owner.

Rationale for Introduction: The only revisions made to this version of PRC-004-2.1a(X) are revisions to Requirements R2 and R3 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.

This version is labeled PRC-004-2.1a(X) for balloting purposes. The 'X' indicates that a version number will be applied at a later time, because multiple versions of PRC-004 ~~are~~ have been in development. The 'X' designation reflects the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. Depending on the timing of approvals of other versions and other factors, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

5. **Effective Date:** ~~The standard shall become effective on the first day after the date this 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 after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction~~See the implementation plan for this Standard.

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 ~~Bulk Power System~~BES, Requirement R2 and Requirement R3 reflect the threshold consistent with the revised BES definition. See paragraph 20 of FERC Order Approving Revised Definition in Docket No. RD14-2-000. The intent of Requirement R2 and Requirement R3 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

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

- For Misoperations occurring on the P~~p~~rotection S~~s~~ystems 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, this requirement does not apply.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

- For Misoperations occurring on the P~~p~~rotection S~~s~~ystems 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, this requirement does not apply.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. 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. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

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1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

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The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	

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2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
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2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
TBD (balloted as 2.1a(X))	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of Requirements to BES dispersed power producing resources

Appendix 1[1]

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
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[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.
3. 45-day formal comment period with initial ballot conducted July 10, 2014 through August 26, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. The currently effective version of PRC-004, i.e., PRC-004-2.1a, also is under active standard development. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	September – October 2014
Final ballot	October 2014
BOT adoption	November 2015

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 (—).”	01/20/06

		2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by NERC Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC’s Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add “…and generator interconnection Facility…”	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by NERC Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	TBD	Applicability revised to clarify application of Requirements to BES dispersed power producing resources	Standard revised in Project 2014-01

When this standard has received ballot approval, the rationale boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**
2. **Number:** PRC-004-4
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.[1]

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.

Rationale for Introduction: The only revisions made to this version of PRC-004 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.

The DGR version of this standard had been labeled PRC-004-4 for balloting purposes. The 'X' had indicated that a version number would be applied at a later time, because multiple versions of PRC-004 were in development at the time of the previous posting. The 'X' designation reflected the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. However, PRC-004-3 was approved by the NERC Board of Trustees on August 14, 2014, so this version has been designated PRC-004-4 to indicate that this version is the successor version.

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

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.

5. Background:

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- 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.
- 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).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed

as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

6. Effective Dates:

See the implementation plan for this Standard.

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
R1	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
R3	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
R4	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
R5	Operations Planning, Long-Term Planning	Medium	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. OR (See next page)	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. OR (See next page)	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. OR (See next page)	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. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

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.[2]

[2] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] 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*[4]; 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*[5] 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[6]." 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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3 http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

4 "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

5 "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

6 "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.

> **Example7c:** 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*[7] 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.

> **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.

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

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.[8]

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.

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*

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

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).

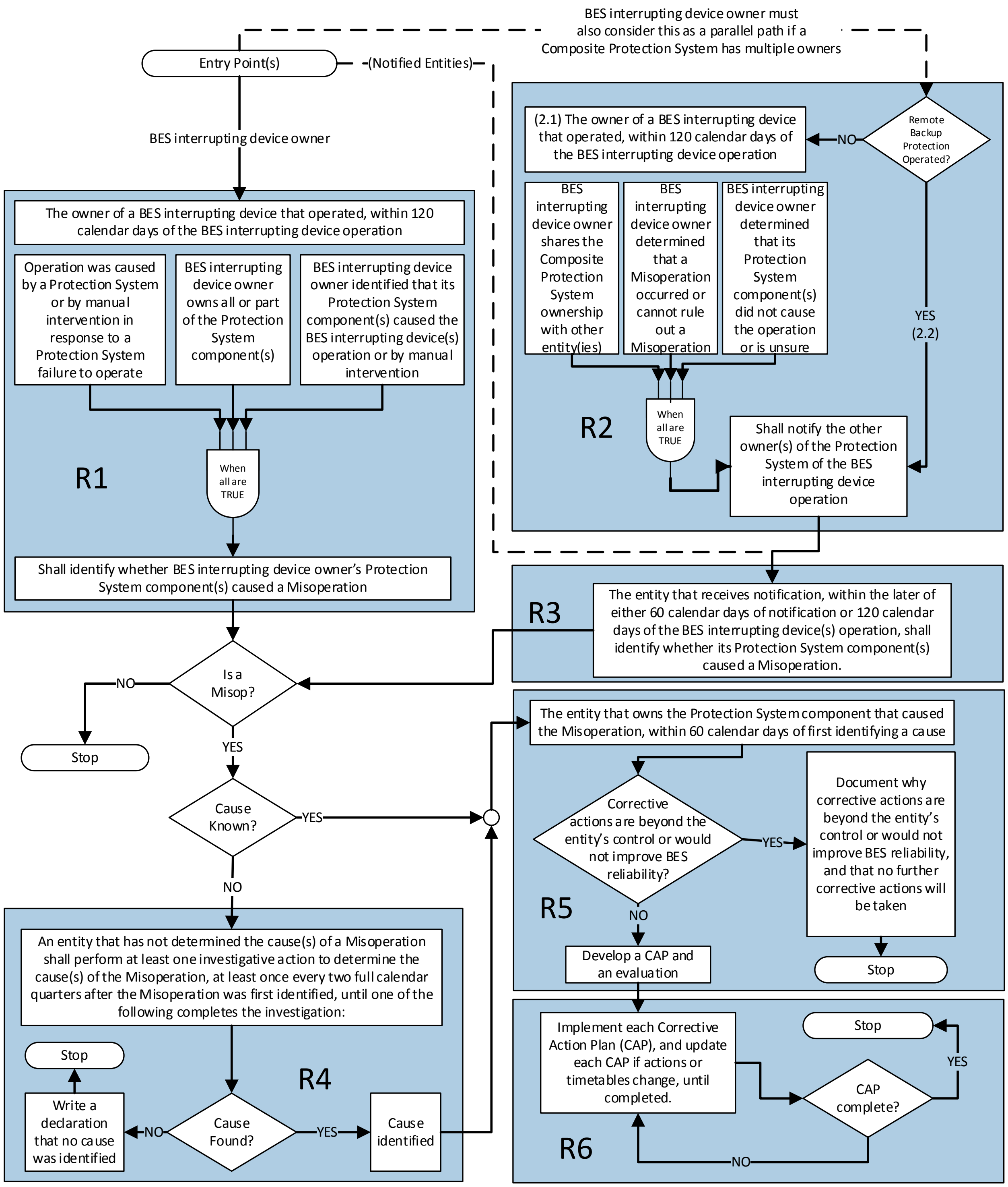
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance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



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.
3. ~~2.~~3. 45-day formal comment period with initial ballot conducted July 10, 2014 through August 26, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. The currently effective version of PRC-004, i.e., PRC-004-2.1a, also is under active standard development. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
~~45-day Formal Comment Period with Initial Ballot~~	~~July – August 2014~~
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	September – October 2014
Final ballot	~~November~~ October 2014
BOT adoption	~~February~~ November 2015

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. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by ~~the~~ NERC Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by ~~the~~ NERC Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
3	~~TBD~~August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
~~TBD (balloted as 3(X))~~4	TBD	~~Standard revised in Project 2014-01~~Applicability revised to clarify application of Requirements to BES dispersed power producing resources	Standard revised in Project 2014-01~~Applicability revised to clarify application of~~

			~~Requirements to BES dispersed power producing resources~~

When this standard has received ballot approval, the rationale boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**
2. **Number:** PRC-004-~~3~~4
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.[1]

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.

Rationale for Introduction: The only revisions made to this version of PRC-004 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.

The DGR version of this standard had been labeled PRC-004-4 for balloting purposes. The 'X' had indicated that a version number would be applied at a later time, because multiple versions of PRC-004 were in development at the time of the previous posting. The 'X' designation reflected the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. However, PRC-004-3 was approved by the NERC Board of Trustees on August 14, 2014, so this version has been designated PRC-004-4 to indicate that this version is the successor version.

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

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.

5. Background:

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- 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.
- 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).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

6. Effective Dates:

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

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, ~~Disturbance Monitoring Equipment (~~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, ~~Disturbance Monitoring Equipment (~~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
R1	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
R3	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
R4	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
R5	Operations Planning, Long-Term Planning	Medium	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. OR (See next page)	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. OR (See next page)	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. OR (See next page)	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. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

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.[2]

[2] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] 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*[4]; 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*[5] 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[6]." 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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[3] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[4] "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

[5] "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

[6] "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.

> **Example7c:** 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 ~~Disturbance Monitoring Equipment (~~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*[7] 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.

> **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

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

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.[8]

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.

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: 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).

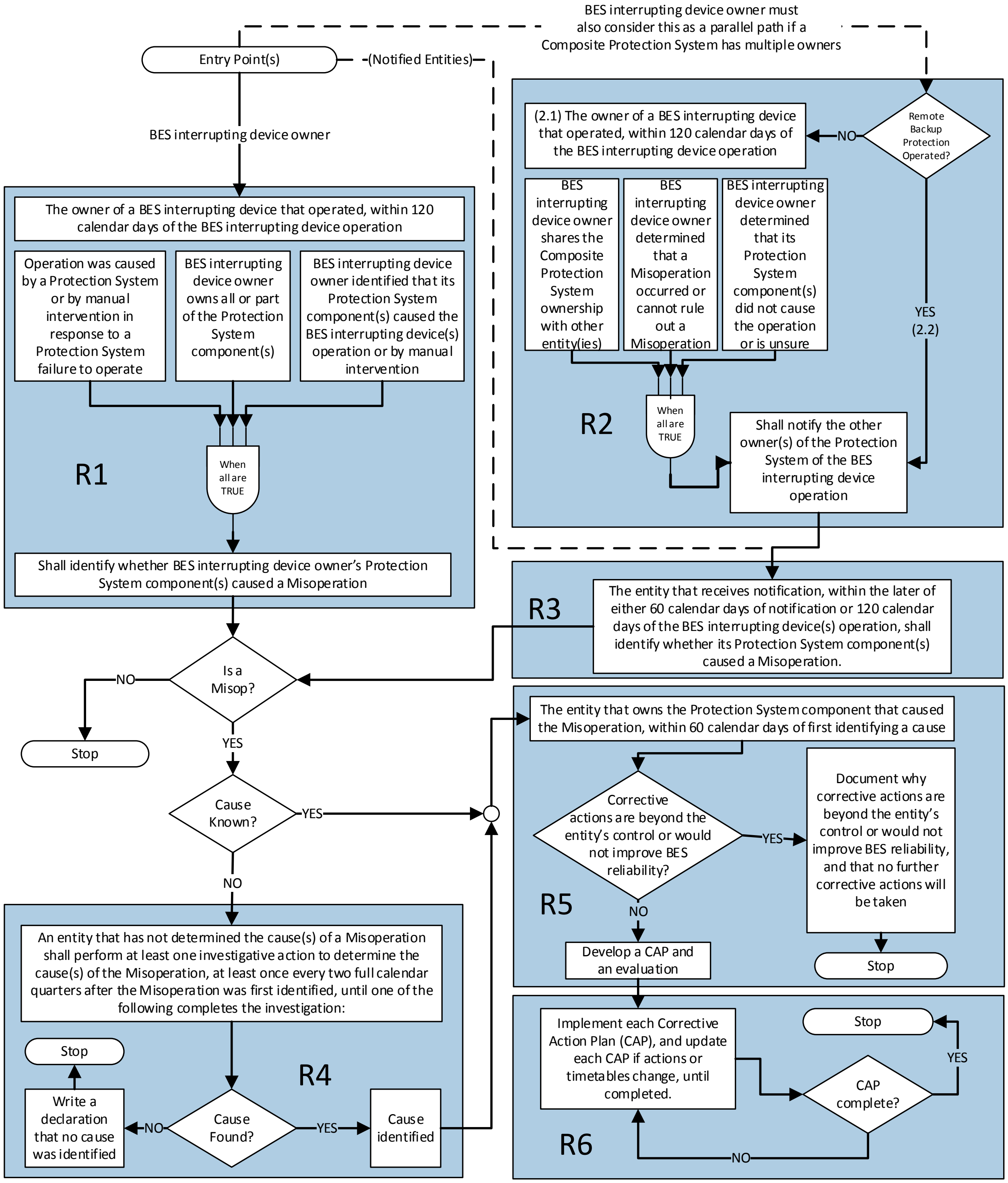
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance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



~~Standard Development Timeline~~

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.
3. 45-day formal comment period with initial ballot conducted July 10, 2014 through August 26, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. The currently effective version of PRC-004, i.e., PRC-004-2.1a, also is under active standard development. ~~Depending on the timing of regulatory approval, this interim version, which has been labeled PRC-004-3(X) for balloting purposes, may be filed for regulatory approval.~~ Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
~~45-day Formal Comment Period with Initial Ballot~~	~~July – August 2014~~
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	September – October 2014
Final ballot	~~November~~October 2014
BOT adoption	~~February~~November 2015

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by ~~the~~NERC Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC’s Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add “…and generator interconnection Facility…”	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by ~~the~~NERC Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	

3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
~~TBD (balloted as 3(X))~~4	TBD	~~Standard revised in Project 2014-01~~Applicability revised to clarify application of Requirements to BES dispersed power producing resources	~~Applicability revised to clarify application of Requirements to BES dispersed power producing resources~~Standard revised in Project 2014-01

When this standard has received ballot approval, the ~~text~~rationale boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**
2. **Number:** PRC-004-~~3~~4
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.[1]

4.2.1.3 Special Protection Systems (SPS).

4.2.1.4 Remedial Action Schemes (RAS).

~~**4.2.1.3**~~**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.

> **Rationale for Introduction:** The only revisions made to this version of PRC-004 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.
>
> ~~This~~The DGR version ~~is~~of this standard had been labeled PRC-004-~~3(X)~~4 for balloting purposes. The 'X' ~~indicates~~had indicated that a version number ~~will~~would be applied at a later time, because multiple versions of PRC-004 ~~a~~were in development~~.~~ at the time of the previous posting. The 'X' designation reflect~~s~~ed the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. ~~Depending on~~ However, PRC-004-3 was approved by the ~~timing of approvals of other versions,~~ NERC ~~may file~~Board of Trustees on August 14, 2014, so this ~~interim~~ version has been designated PRC-004-4 to ~~provide regulatory certainty for entities as~~ indicate that this version is the ~~revised BES definition is implemented~~successor version.

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

~~**Rationale for Applicability:** Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions.~~**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 ~~Bulk-Power System~~BES, 4.2.1.~~3~~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.~~3~~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. ~~Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are not included in this standard because they are planned to be handled in the second phase of this project.~~

5. Background:

A key ~~element~~factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the ~~r~~Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- 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.
- 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).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition need~~s~~ed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also include~~s~~d clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed ~~r~~Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

6. Effective Dates:

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

~~In the Western Interconnection, the standard shall become effective on the first day of the first calendar quarter that is twenty-four months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. In the Western Interconnection, where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

See the implementation plan for this Standard.

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 ~~when~~: *[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.**~~ **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 ~~below.:~~. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 ~~When~~For a BES interrupting device ~~is operated~~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) ~~of~~that share Misoperation identification responsibility for the Composite Protection System ~~when~~under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other ~~entity~~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 ~~When~~For a BES interrupting device ~~is operated~~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~~, 2.2,~~ and 2.~~3~~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, ~~shall~~ 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, ~~Disturbance Monitoring Equipment (DME)~~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, ~~Disturbance Monitoring Equipment (~~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): ~~a dated~~ CAP and evaluation, or ~~a dated~~ 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 ~~hard copy~~hardcopy format): ~~dated~~ 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 ~~for~~, 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

~~Periodic Data Submittal~~

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
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether ~~or not~~ 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 ~~or not~~ 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 ~~or not~~ 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 ~~or not~~ 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 ~~or not~~ 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
R3	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
R4	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
R5	Operations Planning, Long-Term Planning	Medium	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. OR (See next page)	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. OR (See next page)	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. OR (See next page)	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. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

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

~~None.~~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.[2]

[2] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] 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*[4]; 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*[5] 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[6]." 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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[3] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[4] ~~http://www.nerc.com/files/2011_RARPR_FINAL.pdf~~ "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

[5] "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

[6] "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 ~~u~~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 ~~remote~~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 ~~entity must consider the entire Protection System associated with the BES interrupting device that operated. Additionally, the definition accounts for those Protection Systems with multiple levels of protection (e.g., redundant systems), such that if one component fails, but the overall intended performance of the composite protection is met – it would not be identified as a Misoperation under the definition~~overall performance of an Element's total complement of protection should be considered while evaluating an operation.

~~(ADD AN EXAMPLE which includes the following terms)~~

~~INCLUDE DISCUSSION of:~~

~~Primary~~

~~Secondary~~

~~Local Backup~~

~~Communication-assisted relay, and~~

~~Breaker failure not being in the definition.~~

~~The purpose of having the definition of Composite Protection System is to promote reliability and not to penalize entities for implementing redundant protection (e.g., primary and secondary protection). A failure of the primary system when secondary system operates correctly is not a Misoperation of system A because the Composite Protection System (overall) operated correctly to protect the given Element~~

~~Example: There are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that mean the Composite Protection System did not misoperate?~~

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 ~~for which it is designed. Delayed clearing~~if the duration of ~~a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or~~its operating time resulted in the operation of ~~any~~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 ~~for which it is designed~~, such as a power swing, undervoltage, overexcitation, or loss of excitation~~. Delayed clearing~~, if the duration of ~~a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or~~its operating time resulted in the operation of ~~any~~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 ~~for which it is not designed. A~~. 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.

- ~~Paglow:~~ A breaker failure operation does not, in itself, constitute a Misoperation.
- A ~~R~~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 ~~and examples~~ of what ~~is~~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 ~~to clear the Fault~~.
>
> **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 ~~another component of~~ the generator's Composite Protection System operated as intended ~~(e.g.,~~ 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 ~~3~~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 ~~line's~~breaker's Composite Protection System to operate as quickly as intended ~~for a line Fault is a Misoperation. A line to line fault in a weak portion of the system resulted in positive sequence currents below the overcurrent supervision pickup for a line current differential relay. The relay's negative sequence differential element operated instead. However,~~ to meet the ~~original relay settings did not account~~expected critical Fault clearing time for ~~the additional detection time required for the negative sequence element~~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.

~~Installing high-speed protection may be a part of a utility's standard practice without having the need for high-speed protection to prevent voltage or dynamic instability or to maintain relay coordination. For this case, a "Slow Trip – During Fault" of the high-speed protection is not a Misoperation because it would not negatively impact the dynamic BES performance, unless the Composite Protection System operation is slower than previously identified as being necessary to prevent voltage or dynamic instability. The Composite Protection System must also coordinate with other Protection Systems to prevent the trip (e.g., an over-trip) of additional Protection Systems.~~

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~~ operated slower than the objective of the owner(s).~~. 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~~ operated slower than the objective of the owner(s).~~. 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 ~~failure~~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~~ as quickly as intended for an overexcitation condition is~~. 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 ~~F~~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 ~~6d~~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.

~~Paglow: If the coordination error was at the remote terminal (set too fast), then it is an "Unnecessary Trip" at the remote location. If the coordination error was at the local terminal (set too slow), then it is a "Slow Trip" at the local location.~~

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 ~~which~~that occur w~~it~~hen 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.

~~The above~~Below are examples ~~only, and do not constitute an all-inclusive list~~ of conditions that would ~~not~~ be a Misoperation.

Example7c: 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.

~~In the examples above, the~~The standard is not applicable to operation of the protective relay because ~~it operated~~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, ~~says~~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 ~~R1~~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 ~~r~~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 ~~that~~ 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 ~~Disturbance Monitoring Equipment (DME)~~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~~, it~~. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation ~~until~~for a cause of the ~~entity determines otherwise~~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 ~~or not a Misoperation of~~ its Protection System component(s) ~~occurred.~~ 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*[7] 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.

> **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

~~For~~ Requirement R2 ~~(i.e.,~~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 ~~r~~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

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

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 ~~or~~ (DCB) relaying on 03/03/2014 at 15:43 UTC during an external ~~f~~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~~, it~~. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation ~~until~~for a cause of the ~~entity determines otherwise~~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 ~~latter~~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,~~ the entity~~ 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 ~~even~~ 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, ~~or~~ requesting ~~a necessary~~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.[8]

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.

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: 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 ~~or~~ (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 ~~create~~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~~;~~. ~~i~~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 ~~CAPs~~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 time periods within Requirement R1, R3 and Requirement R5 are distinct and separate. If a cause of a Misoperation is identified quickly, the time period in Requirement R1 or R3 ends and the 60 calendar day period to develop the CAP becomes applicable. The ultimate goal is to keep all time periods as short as possible, including the correction of the cause(s) of the Misoperation. See Requirement R6 for CAP implementation. Where there are multiple Protection System owners involved in a Misoperation, each owner whose Protection System component(s) contributed to the Misoperation is subject to Requirement R5.~~

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 ~~must include~~and an evaluation of other Protection Systems including other locations ~~to~~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 ~~F~~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 ~~in an example~~are examples of ~~a declaration~~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 ~~f~~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 ~~f~~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. ~~The~~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. ~~The~~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. ~~The~~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 ~~03~~04/01/2015~~. Following the timetable change, capacitor~~ 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).

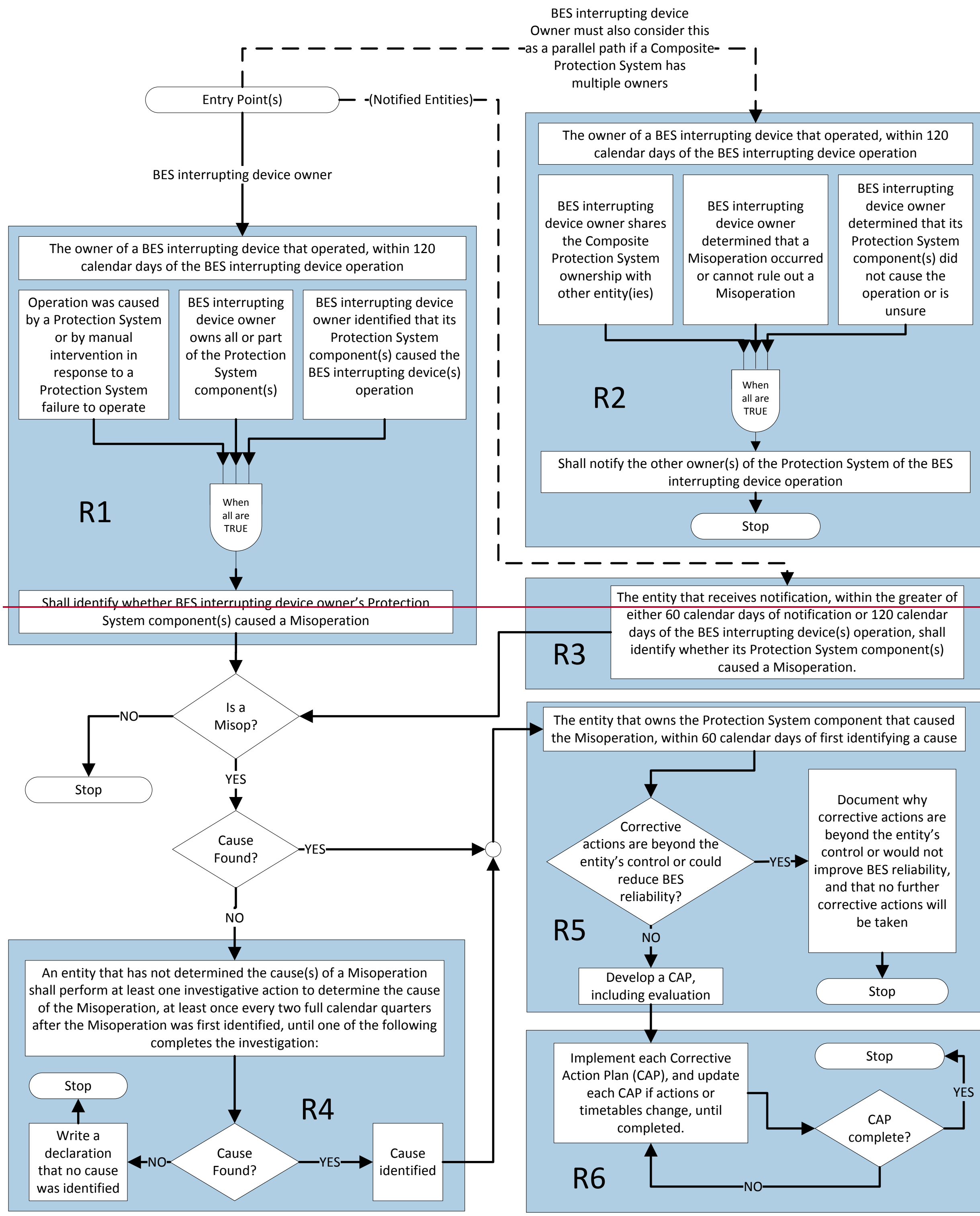
Example R6d: Actions: ~~F~~fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

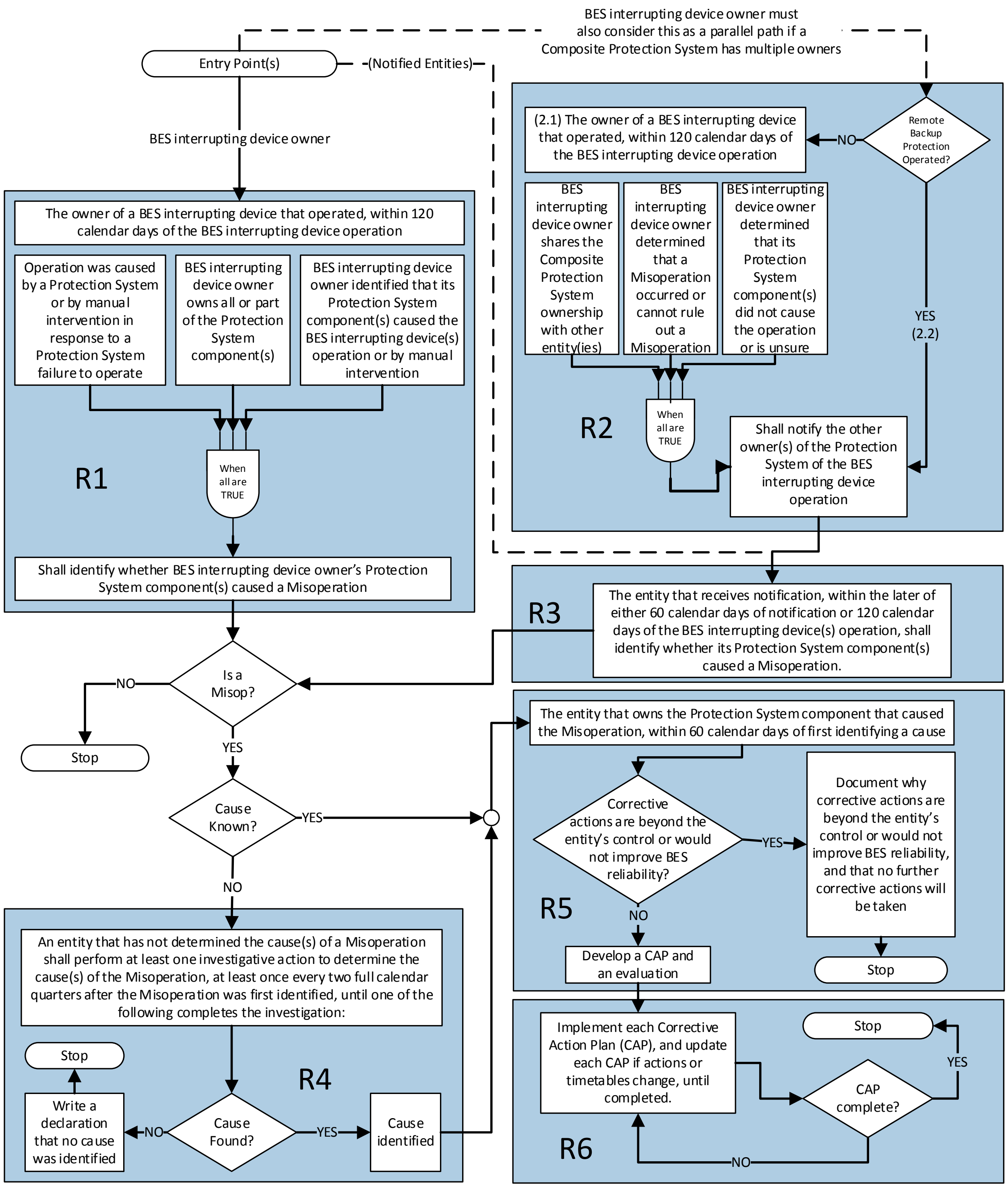
Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware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

CAP completed on 11/10/2014.

The CAP is complete when all of the ~~documented~~ actions ~~to resolve~~identified within the ~~specific problem (i.e., Misoperation) are~~CAP have been completed~~ which may include those actions resulting from the entity's evaluation of other locations, if not addressed through a separate CAP.~~.

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


BES interrupting device Owner must also consider this as a parallel path if a Composite Protection System has multiple owners
Entry Point(s)
(Notified Entities)
BES interrupting device owner
The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
Operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate
BES interrupting device owner owns all or part of the Protection System component(s)
BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation
When all are TRUE
R1
Shall identify whether BES interrupting device owner's Protection System component(s) caused a Misoperation
The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
BES interrupting device owner shares the Composite Protection System ownership with other entity(ies)
BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation
BES interrupting device owner determined that its Protection System component(s) did not cause the operation or is unsure
When all are TRUE
R2
Shall notify the other owner(s) of the Protection System of the BES interrupting device operation
Stop
R3
The entity that receives notification, within the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation.
Is a Misop?
NO
Stop
YES
Cause Found?
YES
NO
The entity that owns the Protection System component that caused the Misoperation, within 60 calendar days of first identifying a cause
Corrective actions are beyond the entity's control or could reduce BES reliability?
YES
Document why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken
R5
NO
Develop a CAP, including evaluation
Stop
An entity that has not determined the cause(s) of a Misoperation shall perform at least one investigative action to determine the cause 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:
Stop
R4
Write a declaration that no cause was identified
NO
Cause Found?
YES
Cause identified
Implement each Corrective Action Plan (CAP), and update each CAP if actions or timetables change, until completed.
Stop
YES
CAP complete?
R6
NO


BES interrupting device owner must also consider this as a parallel path if a Composite Protection System has multiple owners
Entry Point(s)
(Notified Entities)
BES interrupting device owner
The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
Operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate
BES interrupting device owner owns all or part of the Protection System component(s)
BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or by manual intervention
When all are TRUE
R1
Shall identify whether BES interrupting device owner's Protection System component(s) caused a Misoperation
Remote Backup Protection Operated?
NO
(2.1) The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
BES interrupting device owner shares the Composite Protection System ownership with other entity(ies)
BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation
BES interrupting device owner determined that its Protection System component(s) did not cause the operation or is unsure
YES (2.2)
When all are TRUE
R2
Shall notify the other owner(s) of the Protection System of the BES interrupting device operation
R3
The entity that receives notification, within the later of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation.
Is a Misop?
NO
Stop
YES
Cause Known?
YES
NO
The entity that owns the Protection System component that caused the Misoperation, within 60 calendar days of first identifying a cause
Corrective actions are beyond the entity's control or would not improve BES reliability?
YES
Document why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken
R5
NO
Develop a CAP and an evaluation
Stop
An entity that has not determined the cause(s) of a Misoperation shall perform at least one investigative action 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:
Stop
R4
Write a declaration that no cause was identified
NO
Cause Found?
YES
Cause identified
Implement each Corrective Action Plan (CAP), and update each CAP if actions or timetables change, until completed.
Stop
YES
CAP complete?
R6
NO

Implementation Plan

Dispersed Generation Resources
PRC-004-2.1a(X)

The standard version number currently include an (X) to indicate the version numbering will be updated. PRC-004 has been substantively revised in Project 2010-05.1 concurrently with these revisions that address applicability to dispersed generation resources in this project. Depending on factors such as the timing of respective approvals in each project, NERC will assign the appropriate version number prior to BOT adoption.

Standards Involved

Approval:

- PRC-004-2.1a(X) – Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-2.1a – Protection System Misoperation Identification and Correction

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised Bulk Electric System definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

General Considerations

PRC-004-2.1a(X) is proposed for approval to align the applicability section of PRC-004-2.1a with the revised definition of Bulk Electric System. Given the timing of concurrent standards development of PRC projects, PRC-004-2.1a may already be retired pursuant to an Implementation Plan of a successor version of PRC-004 by the time the revised definition of Bulk Electric System becomes effective for all entities. If this occurs, PRC-004-2.1a(X) will not go into effect.

Effective Date

PRC-004-2.1a(X) shall become effective immediately after 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.

Retirement of Existing Standards:

The existing standard, PRC-004-2.1a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-2.1a(X).

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Implementation Plan

Dispersed Generation Resources
PRC-004-2.1a(X)

The standard version number currently include an (X) to indicate the version numbering will be updated. PRC-004 has been~~is being~~ substantively revised in Project 2010-05.1 concurrently with these revisions ~~to~~ that address applicability to dispersed generation resources in this project. Depending on factors such as the timing of respective approvals in each project, NERC will assign the appropriate version number prior to BOT adoption.

Standards Involved
Approval:

- PRC-004-2.1a(X) – Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-2.1a – Protection System Misoperation Identification and Correction

Prerequisite Approvals:
N/A

Background
In light of the adoption of a revised “Bulk Electric System” definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised “Bulk Electric System” definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and ~~/~~Generator Operator~~ requirement~~s to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk~~-~~ Power System.

General Considerations
PRC-004-2.1a(X) is proposed for approval to align the applicability section of PRC-004-2.1a with the revised definition of “Bulk Electric System.” Given the timing of concurrent standards development of PRC projects, PRC-004-2.1a may already be retired pursuant to an Implementation Plan of a successor version of PRC-004 by the time the revised definition of “Bulk Electric System” becomes effective for all entities. If this occurs, PRC-004-2.1a(X) will not go into effect.

Effective Date
PRC-004-2.1a(X) shall become effective immediately after 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.

Retirement of Existing Standards:

The existing standard, PRC-004-2.1a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-2.1a(X).

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

~~Balancing Authority~~

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Dispersed Generation Resources PRC-004-4

Standards Involved

Approval:

- PRC-004-4 – Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-3 – Protection System Misoperation Identification and Correction

Prerequisite Approvals:

- PRC-004-3 – Protection System Misoperation Identification and Correction[1]

Background

In light of the adoption of a revised Bulk Electric System definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised Bulk Electric System definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

General Considerations

PRC-004-4 is proposed for approval to align the applicability section of PRC-004-3 with the revised definition of the Bulk Electric System. The intent of the SDT was to allow for flexibility of the PRC-004 applicability section regardless of the version that is currently in effect when an applicable governmental authority acts on the PRC-004-3 filing. Currently, PRC-004-2.1a is in effect as PRC-004-3 (developed in Project 2010-05.1) is pending regulatory approval. Depending on the timing of approvals for various versions of PRC-004, PRC-004-2.1a may still be in effect at the time the revised definition of Bulk Electric System becomes effective for all entities. If this occurs, PRC-004-2.1a(X) will go into effect and PRC-004-4 shall go into effect after the technical revisions developed in Project 2010-05.1 are approved by applicable regulators, or as otherwise provided for in jurisdictions that do not require regulatory approvals.

[1] PRC-004-3 was adopted by the NERC Board of Trustees on August 18, 2014.

Effective Date

PRC-004-4 shall become effective either immediately after 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, or 12 months following the approval of PRC-004-3, whichever is later. Where approval by an applicable governmental authority is not required, the standard shall become effective either 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, or 12 months following the approval of PRC-004-3, whichever is later.

Retirement of Existing Standards:

The existing standard, PRC-004-3, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-4.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Dispersed Generation Resources

PRC-004-~~3(X)~~4

Standards Involved

Approval:

- PRC-004-~~3(X)~~4 – Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-3 – Protection System Misoperation Identification and Correction

Prerequisite Approvals:

- PRC-004-3 – Protection System Misoperation Identification and Correction[1]

Background

In light of the adoption of a revised ~~"~~"Bulk Electric System~~"~~" definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised ~~"~~"Bulk Electric System~~"~~" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and ~~/~~Generator Operator~~ requirement~~s to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk~~-~~ Power System.

General Considerations

PRC-004-4~~3(X)~~ is proposed for approval to align the applicability section of PRC-004-3 with the revised definition of the ~~"~~"Bulk Electric System.~~"~~" The intent of the ~~Standard Drafting Team~~SDT was to allow for flexibility of the PRC-004 applicability section regardless of the version that is currently in effect when an applicable governmental authority acts on the PRC-004-3~~(X)~~ filing. Currently, PRC-004-2.1a is in effect as PRC-004-3 ~~is currently being(~~developed in Project 2010-05.1) is pending regulatory approval. Depending on the timing of approvals for various versions of PRC-004, PRC-004-2.1a may still be in effect at the time the revised definition of ~~"~~"Bulk Electric System~~"~~" becomes effective for all entities. If this occurs, PRC-004-2.1a(X) will go into effect and PRC-004-4~~3(X)~~ shall go into effect ~~once~~ after the

[1] PRC-004-3 was adopted by the NERC Board of Trustees on August 18, 2014.

technical revisions developed in Project 2010-05.1 are approved by applicable regulators, or as otherwise provided for in jurisdictions that do not require regulatory approvals.

Effective Date

PRC-004-~~3(X)~~4 shall become effective either immediately after 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, or 12 months following the approval of PRC-004-3, whichever is later. Where approval by an applicable governmental authority is not required, the standard shall become effective either 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, or 12 months following the approval of PRC-004-3, whichever is later.

Retirement of Existing Standards:

The existing standard, PRC-004-3, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-~~3(X)~~4.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

~~Balancing Authority~~

Unofficial Comment Form

Project 2014-01 Applicability for Dispersed Generation Resources Standards

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on **Project 2014-01 Dispersed Generation Resources "high-priority" Reliability Standards (PRC-004-2.1a(X) and PRC-004-4)**. The electronic comment form must be completed by **8 p.m. Eastern on Wednesday, October 22, 2014**.

If you have questions please contact Sean Cavote or by telephone at 404.446.9697.

All documents for this project are available on the project page.

Background Information

This posting solicits formal comments on one of three Project 2014-01 Dispersed Generation Resources (DGR) "high-priority" Reliability Standards as identified in the draft white paper (White Paper) prepared by the Project 2014-01 (Project) drafting team (DGR SDT).

The goal of the Project is to ensure that the Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System, as the characteristics of operating dispersed power producing resources can be unique. In light of the revised Bulk Electric System (BES) definition approved by the Federal Energy Regulatory Commission in 2014, the intent of this Project is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources where the status quo does not create a reliability gap.

The DGR SDT performed a review of all standards that apply to GOs and GOPs and categorized how each standard should be applied to dispersed power producing resources to accomplish the reliability purpose of the standard. The DGR SDT developed the White Paper to explain its approach, which was posted on April 17, 2014 for an informal comment period.[1] The industry feedback received on the White Paper allowed the DGR SDT to refine its approach and finalize recommended revisions to the standards. As part of this review the DGR SDT determined that there are three high-priority standards in which immediate attention is required to provide direction to industry stakeholders as soon as feasible regarding how to appropriately direct compliance related preparations:

- PRC-004-2.1a;
- PRC-005; and

[1] The current version of the White Paper can be downloaded on the Project web page at http://www.nerc.com/pa/Stand/Pages/Project-2014-01-Standards-Applicability-for-Dispersed-Generation-Resources.aspx.

- VAR-002.[2]

Because each of the "high-priority" standards has recently been revised or is undergoing revision in another current or recent project, the DGR SDT has developed revisions to multiple versions of each standard to allow for different possibilities in the timing of regulatory approvals. When the revisions are being applied to a version that is not the last approved version of the standard or to a version that is pending regulatory approval, the version is noted with "(X)" after it. For example, this posting includes PRC-004-2.1a(X), which proposes applicability changes to PRC-004-2.1a.[3] Please note that any versions of the standards posted under this project with an "X" suffix will have a version number applied at a later time in order to manage sequencing of version numbers. The intent of balloting the recommended applicability revisions separately from the technical changes that are ongoing in other projects is to provide flexibility to allow approved applicability revisions to move forward on an expedited timeline as needed to support implementation of the revised definition of BES.

The DGR SDT responded to industry comments as contained in its Consideration of Comments, which is posted on the project page, along with the DGR SDT's response to comments on the original Standards Authorization Request (SAR) that defines the scope of this Project.

The DGR SDT continues to coordinate with other NERC Reliability Standards projects currently under development to ensure continuity and to develop a posting strategy that ensures all applicability changes approved by ballot are filed and implemented as quickly as possible without adversely impacting other projects. The DGR SDT Coordination Plan posted on the project page details that coordination.

Summary of Proposed Changes

The DGR SDT's recommended changes are limited to revising the applicability of the relevant versions of PRC-004 to ensure that the requirements of the standard are applied appropriately for dispersed power producing resources included in the BES through Inclusion I4 of the definition of the BES. Although the redlined versions of the standard included with this posting contain changes that appear structurally different, the substance of the changes in each respective set of standards is the same.

The DGR SDT has posted the following standards, along with corresponding implementation plans:

- PRC-004-2.1a(X) (clean and redlined against the last posted version of PRC-004-2.1a(X), and the currently effective PRC-004-2.1a)
- PRC-004-4 (clean and redlined against the last posted version of PRC-004-3(X), and the last NERC Board of Trustees approved version PRC-004-3)

Please note that the DGR SDT has not revised the Violation Risk Factors (VRFs) or Violation Severity Levels (VSLs) associated with the subject standards because the proposed revisions do not change the reliability

[2] Relevant versions of PRC-005 (PRC-005-2(X), PRC-005-3(X), and PRC-005-X(X)) and VAR-002 (VAR-002-2b(X) and VAR-002-4) were posted for a 45-day comment period on June 12, 2014.
[3] PRC-004-2.1a is the currently effective version of the standard. The NERC Board of Trustees approved PRC-004-3 on August 14, 2014.

intent or impact of any of the requirements. If the applicability recommendations are approved by industry, the DGR SDT's intent is that the VRFs and VSLs for each requirement would be unchanged from those either previously approved (for currently enforceable versions of standards or those pending regulatory approval) or would be developed by the drafting team responsible for revising technical content (for those versions of standards currently in development in another standards project).

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you agree with the revisions made in proposed PRC-004-2.1a(X) to clarify applicability of PRC-004-2.1a to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

2. Do you agree with the revisions made in proposed PRC-004-4 to clarify applicability of PRC-004-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

3. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

   Yes:

   No:

   Comments:

Project 2014-01 Dispersed Generation Resources

DRAFT Plan for Standards Drafting Team Coordination and Balloting Multiple Versions of Standards | September 5, 2014

Background

Pursuant to the Standards Authorization Request for this project posted on November 20, 2014, the Project 2014-01 Dispersed Generation Resources standards drafting team (DGR SDT) proposes to modify PRC-004-2.1a, PRC-004-3, PRC-005-2, PRC-005-3, PRC-005-X, VAR-002-2b, and VAR-002-3 to account for the unique characteristics of dispersed power producing resources. As the DGR SDT has explained in the White Paper it has developed and posted on its project page, the DGR SDT has classified each of these standards as high-priority standards requiring applicability changes as soon as practicable.

Because each of the high-priority standards has recently been revised or is undergoing revision in another active standard development project, the DGR SDT has developed revisions to multiple versions of each standard to allow for different possibilities in the timing of regulatory approvals. Specifically, two of the three standards identified by the DGR SDT as high priority (PRC-004 and PRC-005) are being or have recently been revised by other projects. NERC and the DGR SDT recognize that developing multiple versions of the same standard in different projects may be confusing; however, developing and balloting the recommended DGR applicability revisions separately from the technical changes that are ongoing in other active standard development projects provides flexibility in effectuating applicability revisions on an expedited timeline as needed to support implementation of the revised definition of the Bulk Electric System. The DGR project is being carefully coordinated with other active standard development projects with careful consideration of the period of time various versions of each standard may be in effect.

When DGR revisions are applied to a standard version that is not the last approved version of the standard or to a standard version that may be superseded by another version in active standard development outside the DGR project, the version is noted with "(X)" after it. For example, the DGR SDT is developing PRC-005-2(X), which proposes applicability changes to PRC-005-2, as well as PRC-005-3(X), which proposes applicability changes to PRC-005-3. Please note that NERC will apply at a later time the appropriate version numbers to standard versions containing an "X" suffix in order to effectively manage sequencing of version numbers in these projects.

PRC-004 DGR Applicability Modifications

PRC-004-2.1a (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) is FERC-approved and has been enforceable since November 25, 2013. PRC-004-3 was in active standard development in Project 2010-05.1 and has been approved by the NERC Board of Trustees (Board). PRC-004-3 will supersede PRC-004-2.1a; however, until PRC-004-3 is approved by applicable government authorities and becomes enforceable, there may be a need for revisions to tailor the applicability of PRC-004-2.1a, which the DGR SDT has balloted as PRC-004-2.1a(X). The proposed implementation period for PRC-004-3 is 12 months.

PRC-004-3 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) was in active standard development in Project 2010-05.1 Protection System Misoperations, and was approved by the Board on August 18, 2014. The DGR SDT and the Protection System Misoperations SDT coordinated regarding changes to the applicability of PRC-004. The DGR SDT has balloted proposed applicability revisions to PRC-004-3 as PRC-004-4.

Depending on the timing of the applicable governmental authorities approving PRC-004-3, both PRC-004-2.1a(X) and PRC-004-4 may be needed.

PRC-005 DGR Applicability Modifications

PRC-005-2 (Protection System Maintenance): PRC-005-2 is FERC-approved and will become enforceable on April 1, 2015. PRC-005-2 has a 12-year phased-in implementation period and may be enforceable for a period of time before PRC-005-3 becomes enforceable after approval by the applicable government authorities. Therefore, the DGR SDT is balloting proposed revisions to the applicability of PRC-005-2 as PRC-005-2(X).

PRC-005-3 (Protection System and Automatic Reclosing Maintenance): PRC-005-3 was adopted by the Board on November 7, 2013 and filed with the applicable governmental authorities on February 14, 2014. Upon regulatory approval, PRC-005-3 will supersede PRC-005-2, and according to its proposed implementation plan, will continue the 12-year implementation period for components included in PRC-005-2. Therefore, the DGR SDT is balloting proposed revisions to the applicability of PRC-005-3 as PRC-005-3(X).

PRC-005-X (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance): PRC-005-X is currently in an active standards development project. Language to clarify the applicability of the requirements of PRC-005-X was agreed to by both SDTs and is being balloted in the DGR project as PRC-005-X(X). Depending on the timing of the completion of the DGR project relative to Project 2007-17.3, NERC will determine the appropriate approach to filing applicability changes approved by balloters and adopted by the Board.

VAR-002 DGR Applicability Modifications

VAR-002-2b (Generator Operation for Maintaining Network Voltage Schedules) is FERC-approved and has been enforceable since July 1, 2013. A successor version, VAR-002-3, is pending regulatory approval and has a proposed implementation period of one quarter. Depending on the timing of regulatory approvals of VAR-002-3, VAR-002-2b may remain in effect. Therefore, the DGR SDT is balloting proposed revisions to clarify the applicability of VAR-002-2b as VAR-002-2b(X).

VAR-002-3 (Generator Operation for Maintaining Network Voltage Schedules) was adopted by the Board on May 7, 2014 and filed with the applicable governmental authorities on June 10, 2014. No other version of VAR-002 is in active standard development outside the DGR project. Therefore, the DGR SDT is balloting proposed revisions to VAR-002-3 as VAR-002-4.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation		
Date Submitted:	10/1/2013		
SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
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. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard.

PRC-005-2

Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply.

FAC-008-3

For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information
Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels. **PRC-023-3/PRC-025-1** In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements. **PRC-004-2** There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above. **VAR-002-2** Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard. **General review of IROs, MODs, PRCs, TOPs** IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

Reliability Functions		
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2014-01 Applicability for Dispersed Generation Resources Standards
PRC-004-2.1a(X) and PRC-004-4

Additional Ballots Now Open through October 22, 2014

Now Available

Additional ballots for two of the **Project 2014-01 Dispersed Generation Resources "high-priority" Reliability Standards (PRC-004-2.1a(X) and PRC-004-4)** as identified in the draft white paper prepared by the Project 2014-01 drafting team are open through **8 p.m. Eastern on Wednesday, October 22, 2014.**

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard by clicking here.

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballots. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Sean Cavote.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-004-2.1a(X) and PRC-004-4

Formal Comment Period Now Open through October 22, 2014

Now Available

A 45-day formal comment period for two of the **Project 2014-01 Dispersed Generation Resources "high-priority" Reliability Standards (PRC-004-2.1a(X) and PRC-004-4)** as identified in the draft white paper prepared by the Project 2014-01 drafting team is open through **8 p.m. Eastern on Wednesday, October 22, 2014.**

Instructions for Commenting

Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot period for the standards will be conducted **October 10-22, 2014.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Sean Cavote,
Standards Developer, or at 404-446-2560.

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Standards Announcement

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Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-004-2.1a(X) and PRC-004-4

Additional Ballot Results

Now Available

Additional ballots for **Project 2014-01 Dispersed Generation Resources Reliability Standards, (PRC-004-2.1a(X) and PRC-004-4)** concluded at **8 p.m. Eastern on Wednesday, October 22, 2014**.

The standards achieved quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

	Ballot Results
	Quorum /Approval
PRC-004-2.1a(X)	85.13% / 94.75%
PRC-004-4	83.29% / 93.98%

Background information for this project can be found on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street,
Standards Development Administrator, or at 404-446-9702.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-004-2.1a_X Additional Ballot Oct 2014
Ballot Period:	10/10/2014 - 10/22/2014
Ballot Type:	Successive
Total # Votes:	332
Total Ballot Pool:	390
Quorum:	**85.13 % The Quorum has been reached**
Weighted Segment Vote:	94.75 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	62	0.939	4	0.061	0	20	19
2 - Segment 2	8	0.2	2	0.2	0	0	0	4	2
3 - Segment 3	85	1	60	0.952	3	0.048	0	17	5
4 - Segment 4	29	1	20	1	0	0	1	3	5
5 - Segment 5	92	1	61	0.938	4	0.062	0	12	15
6 - Segment 6	54	1	34	0.919	3	0.081	0	7	10
7 - Segment 7	3	0.2	1	0.1	1	0.1	0	0	1
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.2	2	0.2	0	0	0	0	0

10 - Segment 10	8	0.8	8	0.8	0	0	0	0	0
Totals	**390**	**6.7**	**253**	**6.348**	**15**	**0.352**	**1**	**63**	**58**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	

1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman		
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	COMMENT RECEIVED
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	

2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg		
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (see previous comments)
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Reference comments by group - Colorado Springs Utilities)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	

3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Abstain	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	NO COMMENT RECEIVED
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	

4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (see previous comments)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden	Negative	COMMENT RECEIVED
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	

5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see previous comments)
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	

6	FirstEnergy Solutions	Kevin Querry		
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra		
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

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Ballot Results	
Ballot Name:	Project 2014-01_ PRC-004-4 Additional Ballot Oct 2014
Ballot Period:	10/10/2014 - 10/22/2014
Ballot Type:	Successive
Total # Votes:	324
Total Ballot Pool:	389
Quorum:	83.29 % The Quorum has been reached
Weighted Segment Vote:	93.98 %
Ballot Results:	The Ballot has Closed

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	104	1	60	0.909	6	0.091	0	20	18
2 - Segment 2	8	0.2	2	0.2	0	0	0	4	2
3 - Segment 3	85	1	54	0.9	6	0.1	0	17	8
4 - Segment 4	29	1	20	1	0	0	1	3	5
5 - Segment 5	92	1	55	0.902	6	0.098	0	12	19
6 - Segment 6	54	1	33	0.892	4	0.108	0	7	10
7 - Segment 7	3	0.2	2	0.2	0	0	0	0	1
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.2	2	0.2	0	0	0	0	0

10 - Segment 10	8	0.7	7	0.7	0	0	0	0	1
Totals	**389**	**6.6**	**238**	**6.203**	**22**	**0.397**	**1**	**63**	**65**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	

1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman		
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	COMMENT RECEIVED
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Karen Silverman, Puget Sound Energy)
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Comments Submitted by Maryclaire Yatsko)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		

1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg		
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (see previous comments)
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Reference Comments by group - Colorado Springs Utilities)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
				COMMENT

3	Kansas City Power & Light Co.	Joshua D Bach	Negative	RECEIVED
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Abstain	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	NO COMMENT RECEIVED
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	

4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (see previous comments)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden	Negative	COMMENT RECEIVED
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	

5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur		
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Karen Silverman)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by Maryclaire Yatsko)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		

5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see previous comments)
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry		
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra		
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Maryclaire Yatsko's comments on behalf of

				Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito		
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Individual or group. (24 Responses)
Name (14 Responses)
Organization (14 Responses)
Group Name (10 Responses)
Lead Contact (10 Responses)
Question 1 (19 Responses)
Question 1 Comments (20 Responses)
Question 2 (18 Responses)
Question 2 Comments (19 Responses)
Question 3 (18 Responses)
Question 3 Comments (19 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
No
Individual
Heather Bowden
EDP Renewables North America LLC
No
Requirement 2 and Requirement 3 should add "in response to electrical quantities."
No
Applicability (4.2.1.5) should include "in response to electrical quantities."
No
Group
Arizona Public Service Co
Janet Smith
Yes
Individual
Thomas Foltz
American Electric Power
Yes
Yes
No
Individual
Jonathan Meyer
Idaho Power
Yes

Yes
No
Individual
John Merrell
Tacoma Power
Yes
Yes
No
Individual
Michelle D'Antuono
Ingleside Cogeneration LP/Occidental Energy Ventures Corp
Yes
Occidental Energy Ventures Corp. (OEVC) agrees that the scope of a Misoperation investigation should be limited to those Protection Systems affiliated with 75+ MVA aggregation points located within a dispersed generation facility. It makes no sense requiring a compulsory NERC-compliant investigation and report down to the windmill or solar panel level – unless somehow the aggregation point is affected. This is unlikely to be the case most of the time, and if every minimal incident is subject to PRC-004-2.1a(X), both the relay owner and CEA community could be overwhelmed with the volume of work required. This serves no useful reliability purpose.
Yes
OEVC agrees that the scope of a Misoperation investigation should be limited to those Protection Systems affiliated with 75+ MVA aggregation points located within a dispersed generation facility. It makes no sense requiring a compulsory NERC-compliant investigation and report down to the windmill or solar panel level – unless somehow the aggregation point is affected. This is unlikely to be the case most of the time, and if every minimal incident is subject to PRC-004-3, both the relay owner and CEA community could be overwhelmed with the volume of work required. This serves no useful reliability purpose.
Yes
OEVC is encouraged by the rapid progress that the DGR SDT has made in the development and approval of the first three priority standards. We appreciate the hard work and are hoping the project team will continue at the same rapid pace in the next grouping.
Individual
Venona Greaff
Occidental Chemical Corporation
Group
Colorado Springs Utilities
Kaleb Brimhall
Individual
Michael Moltane
ITC
Yes
The Standard should define dispersed power producing resource. While in a practical sense this is a facility comprised of wind turbines or PV inverters, offering exclusions from Requirements based on

an undefined criteria is not a good practice. R4 – ITC recommends removal of the sub-bullet under R4 excluding the generators identified through Inclusion I4. The exclusion using BES I4 is confusing and may conflict with existing standard VAR-001-4. A non-BES unit or several non-BES units combined together could have an impact on the BES and thus removing the generators from VAR-002-4 R4 solely based on Inclusion I4 may be affect reliability. Per VAR-001-4 R4, the TOP is required to specify criteria that will exempt generators from following a voltage or reactive power schedule and associated notification requirements. Therefore, ITC recommends that VAR-002-3 R4 should be reworded as “Unless exempted by the Transmission Operator, each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement 3”. The TOP can determine what notifications are necessary and be more specific depending on the needs of the system or individual facility. For example, a TOP exemption criteria may contain: “Dispersed power producing facilities are exempt from reactive capability change notifications less than 10% of the total aggregate lagging reactive capability as measured at the POI at nominal voltage”. TOPs typically will not want to receive individual turbine outage notifications; however, there may be instances where a dispersed power producing resource could lose an individual unit that may affect reliable operations (i.e. large individual units, near nuclear facility). In addition, the sub-bullet language in VAR-002-4 may be interpreted such that generators not in BES are exempt from reactive capability notifications and, in turn, exempt from following schedules which may be in conflict with VAR-001-4 and potentially impact the reliability of the BES. VAR-001-4 requires the TOP to determine the exemption criteria for generators and ITC recommends that VAR-002-4 be consistent with this practice as the TOP may require non-BES generators to follow a voltage or reactive power schedule based on the collective impact to the BES.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
Yes
Yes
Individual
Sonya Green-Sumpter
South Carolina Electric & Gas
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
Yes
No
Individual
John Seelke
Public Service Enterprise Group
No
The changes would create a reliability gap between I4 generators and I2 generators. It also violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: “Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage.” Presently, every generator at a site that exceeds 75 MVA is subject to the standard. All I2 generators, regardless of size, would remain subject to the standard, but all I4 generators would be exempt except at the

point where their output aggregates to greater than 75 MVA. In addition, individual I2 greater than 20 MVA are subject to the standard, regardless of the aggregate output of generation at a common point of connection. We suggest changes to the added bullet in R2 and R3 to make the standard comparable for all resources (added language is CAPITALIZED): "For Misoperations occurring on the Protection Systems of individual [delete "dispersed power producing resources"] GENERATORS identified under INCLUSION I2 AND Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to [delete "75"] 20 MVA of BES facilities, this requirement does not apply."
No
For the same reasons described in Q1 above, part 4.2.1.5 should have similar changes applied.
Yes
The SDT has not provided a technical rationale for its proposed changes but instead has hidden behind the I4 definition. As the SDT well knows, NERC standards may apply to Elements that are not included in the BES definition.
Individual
Maryclaire Yatsko
Seminole Electric Cooperative, Inc.
Yes
No
Seminole agrees with the specific revisions concerning only the changes to distributed generation, however, Seminole does not agree with the ongoing revisions through Project 2010-05.1 that are included in this revision, such as the owner of the BES interrupting device being required to initiate review in all scenarios as opposed to the entity that initiated the interrupting device's action. Therefore, Seminole must vote negative as this revision includes language from Project 2010-05.1 that Seminole does not find agreeable.
No
Individual
David Greyerbiehl
Consumers Energy Company
Yes
Yes
Yes
For this exclusion, the standard formatting was changed from the previous standards and revisions. Was this intentional and why? If so, are the other standards going to be revised similarly.
Group
Dominion
Connie Lowe
Yes
Yes
No
Individual
Bill Temple
Northeast Utilities
Yes

Yes
No
Group
Colorado Springs Utilities
Kaleb Brimhall
Group
Puget Sound Energy
Dianne Gordon
Yes
Yes
Yes
In the proposed Applications and Guidelines for PRC-004-4: The section "Composite Protection System - Breaker Failure Example" reads "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." This example is inconsistent with #1 of the new proposed Misoperation Definition (Failure to Trip - During Fault), which reads "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." The example given above is NOT a Misoperation, because the Composite Protection System operated correctly even with a failed trip coil (from what we understand of what is written).
Group
ACES Standards Collaborators
Jason Marshall
Yes
We agree with the changes. However, one additional change is necessary. “BES facilities” should be changed to the defined term “Facilities.” By definition Facilities would be limited to the BES and would appear to constitute the same meaning that is conveyed by “BES facilities.”
Yes
When reviewing the red-line version of the standard comparing this version to the last posting, we can find no differences pertaining the portion of the standard dealing with dispersed generation resources. Comparing for changes would be much easier if all of the red-lines that do not pertain to this project were changed to black text especially considering PRC-004-3 was approved by the NERC Board of Trustees in their mid-August prior to the posting of this standard.
Yes
The SDT should clarify what is meant by “affected.” Does this mean that amount of generation that was actually outaged as a result of the Misoperation? Or would this include an evaluation of the other potential Misoperations that could have occurred if the same conditions were experienced at other locations within the dispersed generation site? We believe that the answer should be the former rather than the latter. To make this clear, we suggest changing the word “affected” to “outaged” or, at least, providing an explanation in the technical/application guidelines section of the standard.
Group
DTE Electric Co.
Kathleen Black
Yes

Yes
No
Group
SPP Standards Review Group
Shannon V. Mickens
Yes
Yes
We would like to thank the drafting team for taking into consideration our suggestions in reference to replacing the term ‘BPS’ with ‘BES’ in both(PRC-004-2.1a(X) and PRC-004-4) as well as including the new term ‘Composite Protection System’ in PRC-004-4. We felt these suggestions would help maintain consistency with the current documentation and the BES Definition.
Individual
John Pearson/Matt Goldberg
ISO New England
No
In R2 and R3, the words “or could have affected” were initially added but then they were deleted. Those words should not have been deleted or similar replacement language should be added. The PRC subteam had indicated to us that those words would be included. The deleted words addressed the concern we expressed during the comment period for the Dispersed Generation White Paper. Specifically, we stated that we do not agree with limiting the analysis requirement to a trip of greater than 75 MVA because that only accounts for very large occurrences that could be unusual. Smaller occurrences, however, may predict an unusual large occurrence that could impact reliability. Many of these wind turbine installations at different sites all use the same equipment and during a major disturbance reliability may be reduced by misoperations. The deleted words were in fact included in the “Standards Applicability Guidelines” that were circulated for comment but were ultimately not issued. Wording that indicates when misoperations occur on relays that are used in applications that ultimately represent over 75 MVA should be added back in.
No
See Question 1 response
No

Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources
Recommended Applicability Changes to PRC-004

The Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) standards drafting team (DGR SDT)[1] thanks all commenters who submitted comments on the standard. The DGR SDT's recommended changes to the applicability of the standard were posted for a 45-day comment period from September 5, 2014 through October 22, 2014. Stakeholders were asked to provide feedback on the standard and associated documents through an electronic comment form. There were 24 sets of comments, including comments from approximately 77 different entities from approximately 55 companies representing all 10 Industry Segments as shown in the table on the following pages.

Please note that NERC has instituted a new standards numbering convention to account for concurrent changes in draft standards. Specifically, the DGR SDT developed recommended changes to PRC-004 in concert with substantive changes made by other SDTs. As a result, the DGR SDT used an "X" suffix designation to indicate that the standard version number would be changed to the appropriate version number once the standard is filed at the Federal Energy Regulatory Commission (FERC) for consideration. However, the standards numbering convention now in effect has resulted in the following changes to the DGR versions of the PRC-004 standard:

Obsolete Version	Current Version
PRC-004-2.1a(X)	PRC-004-2.1(i)a
PRC-004-3(X)	PRC-004-4

To avoid confusion the DGR SDT has preserved the obsolete versions of the PRC-004 recommended changes for the purpose of responding to comments here. Moving forward this project will adopt the revised version numbering to comply with the standards numbering convention.

All comments submitted may be reviewed in their original format on the standard's project page.

This document contains the DGR SDT's response to all industry comments received during this comment period. The DGR SDT encourages commenters to review its responses to ensure all concerns have been addressed. The DGR SDT notes that a significant majority of commenters agree with the DGR

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably.

SDT's recommendations on the standard, but that several commenters expressed specific concerns. Some comments supporting the DGR SDT's recommendations are discussed below but in most cases are not specifically addressed in this response. Also, several comments in response to specific questions are duplicated in other questions, and several commenters raise substantively the same concerns as others. Therefore, the DGR SDT's consideration of all comments is addressed in this section in summary form, with duplicate comments treated as a single issue. Any comments made on another standard are addressed in the DGR SDT's response to comments on that standard.

1. Summary Consideration

Based on the results from the recent comment and ballot period, it appears that industry overwhelming agrees with the DGR SDT's recommendations to make applicability changes to PRC-004 to account for the unique characteristics of DGRs in the standard. However, there are some disagreements among stakeholders and typographical errors contained in and illuminated by industry comments. The DGR SDT has carefully reviewed and considered each stakeholder comment and has revised its recommendations where suggested changes are consistent with DGR SDT intent and industry consensus. However, all recommended changes are non-substantive as contemplated by the NERC Standard Processes Manual and therefore do not require an additional ballot. The DGR SDT's consideration of all comments follows.

2. General Comments

At least one commenter requested that the red-lined version of the posted standard contain only red-lined text to those changes made by the DGR SDT. The red-lined version of the standard that will be posted for final ballot will consist of red-lined text limited to those changes made by the DGR SDT since the last posted version.

At least one commenter made inquiries related to the format of the standard. The DGR SDT notes that as standards are revised, they will be updated to the most current standard format.

3. PRC-004

At least one commenter suggested that Requirement R2 and Requirement R3 should add "in response to electrical quantities." The DGR SDT notes that relays that respond to "electrical quantities" is included in the definition of Protection System as defined by the NERC Glossary of Terms; therefore, the DGR SDT elects to retain the language as drafted to avoid redundancy that would result from adding the suggested language.

At least one commenter believes that in Requirements R2 and R3 of PRC-004-2.1a(X) and section 4.2.1.3 of PRC-004-4, "75 MVA" should be changed to "20 MVA" to make it comparable to I2 generators. The commenter believes that although the change to 20 MVA would have this standard apply to non-BES assets, many standards do likewise. The commenter notes that "Protection Systems," which are the subject of this standard, are non-BES. As written, according to the commenter, a reliability gap would be created between I4 generators and I2 generators. The commenter believes that the proposed change violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: "Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage."

As the DGR SDT has explained before, in order to provide consistent requirements for all generation, the DGR SDT believes it is necessary to assess applicability on individual units greater than 20 MVA and aggregate generation greater than 75 MVA, which are thresholds that have been explicitly recognized and approved by FERC as an appropriate threshold for these types of facilities consistent with the revised BES definition. The DGR SDT therefore does not believe it would be appropriate to use different aggregation thresholds absent a robust technical justification to do so. Moreover, the DGR SDT does not believe that a reliability gap is created, nor any unfair competitive advantages are given as a result.

At least one commenter notes that in Requirements R2 and R3, the words "or could have affected" were initially added but then deleted. The commenter believes those words should not have been deleted because the DGR PRC subteam had indicated that those words would be included. The deleted words addressed the commenter's concern it expressed during the comment period for the Dispersed Generation White Paper. Specifically, the commenter stated that it does not agree with limiting the analysis requirement to a trip of greater than 75 MVA because that only accounts for very large occurrences that could be unusual. The commenter believes that smaller occurrences, however, may predict an unusual large occurrence that could impact reliability, and that the deleted words were in fact included in the "Standards Applicability Guidelines" that were circulated for comment but were ultimately not issued.

As the DGR SDT has previously explained, it has considered all industry comments on this issue and determined that the use of "could have affected" is too vague, and that proving or disproving whether an event or a single misoperation could have affected 75 MVA would be overly burdensome. The use of "affected" was determined to still be broad enough to include misoperations that did not result in an actual trip of the associated generator, for instance the situation in which a protection system failed to trip 75 MVA of nameplate generation when a trip should have occurred. Note that the proposed language revision does not refer to the actual generation of the site at the time of the event, but rather what the generators that experienced the misoperation(s) are capable of producing at nameplate rating. The DGR SDT believes that this addresses the concerns raised and therefore respectfully declines to adopt the commenter's suggestion.

At least one commenter suggested that the term "BES facilities" should be replaced with the defined term "Facilities." By definition Facilities would be limited to the BES and would appear to constitute the same meaning that is conveyed by "BES facilities." The DGR SDT agrees that this comment may have merit and therefore is referring it to NERC for future consideration when the standard is reviewed in a future project.

Some commenters expressed agreement with limiting the scope of a misoperation investigation to those Protection Systems affiliated with 75+ MVA aggregation points located within a dispersed generation facility. The SDT drafted its recommendation with the understanding that generator owner obligations as required by the standard would only occur at individual power producing resources if the misoperation affects an aggregate nameplate rating of greater than 75 MVA.

At least one commenter agrees with the specific revisions concerning only the changes to distributed generation but does not agree with the ongoing revisions through Project 2010-05.1 that are included in this revision, such as the owner of the BES interrupting device being required to initiate review in all scenarios as opposed to the entity that initiated the interrupting device's action. Therefore, the commenter indicates that it intends to vote negative, as this revision includes language from Project 2010-05.1 that the commenter does not find agreeable.

The scope of the DGR SDT is to specifically address standards applicability to dispersed power producing resources identified under Inclusion I4 of the BES definition. Therefore, these comments will be provided to NERC staff and to the Project 2010-5.1 SDT to the extent it remains active on these issues, as the DGR SDT believes these issues should be addressed on a broader and technology-neutral scope.

At least one commenter indicated that the DGR SDT should clarify what they mean by "affected" by changing the word "affected" to "outaged." The use of the term "affected" instead of "outaged" was intended to address the situation in which a Protection System failed to trip a generator(s) and create an outage. This situation is also a "Misoperation" and would not be addressed by the use of "tripped" or "outaged." The SDT notes that the 75 MVA value refers to aggregate nameplate generation.

At least one commenter believes the standard should define dispersed power producing resource. The DGR SDT maintains that this issue is adequately addressed in the White Paper. The DGR SDT believes that the proposed language as it exists adequately describes the treatment of dispersed power producing resources, a position that is supported by clear industry consensus.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co, of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Brian Robinson	Utility Services	NPCC	8
9.	Kathleen Goodman	ISO - New England	NPCC	2
10.	Helen Lainis	Independent Electricity System Operator	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11.	Michael Jones	National Grid	NPCC	1
12.	Mark Kenny	Northeast Utilities	NPCC	1
13.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
2.	Group	Janet Smith	Arizona Public Service Co	X		X		X	X				
N/A													
3.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
N/A													
4.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Coop	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Ken Goldsmith	Alliant Energy	MRO	4
8.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
9.	Marie Knox	MISO	MRO	2
10.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
11.	Randi Nyholm	Minnesota Power	MRO	1, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
12. Scott Nickels		Rochester Public Utilities	MRO 4										
13. Terry Harbour		MidAmerican Energy	MRO 1, 3, 5, 6										
14. Tom Breene		Wisconsin Public Service	MRO 3, 4, 5, 6										
15. Tony Eddleman		Nebraska Public Utilities District	MRO 1, 3, 5										
5.	Group	Connie Lowe	Dominion	X		X		X	X				
Additional Member		**Additional Organization**	**Region** / **Segment Selection**										
1. Randi Heise		NERC Compliance Policy	SERC 1, 3, 5, 6										
2. Larry Nash		Electric Transmission	SERC 1, 3										
3. Louis Slade		NERC Compliance Policy	RFC 5, 6										
4. Mike Garton		NERC Compliance Policy	NPCC 5										
6.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
N/A													
7.	Group	Dianne Gordon	Puget Sound Energy	X		X		X					
N/A													
8.	Group	Jason Marshall	ACES Standards Collaborators						X				
Additional Member		**Additional Organization**	**Region** / **Segment Selection**										
1. Chip Koloini		Golden Spread Electric Cooperative, Inc.	SPP 3, 5										
2. Scott Brame		North Carolina Electric Membership Corporation	SERC 3, 4, 5										
3. Ellen Watkins		Sunflower Electric Power Corporation	SPP 1										
4. Bob Solomon		Hoosier Energy Rural Electric Cooperative, Inc.	RFC 1										
9.	Group	Kathleen Black	DTE Electric Co.			X	X	X					
Additional Member		**Additional Organization**	**Region** / **Segment Selection**										
1. Kent Kujala		NERC Compliance	RFC 3										
2. Daniel Herring		NERC Training & Standards Development	RFC 4										
3. Mark Stefaniak		Merchant Operations	RFC 5										
10.	Group	Shannon V. Mickens	SPP Standards Review Group		X								
Additional Member		**Additional Organization**	**Region** / **Segment Selection**										
1. Stephanie Johnson		Westar Energy, Inc.	SPP 1, 3, 5, 6										
2. Bo Jones		Westar Energy, Inc.	SPP 1, 3, 5, 6										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
3. Tiffany Lake	Westar Energy, Inc.	SPP	1, 3, 5, 6									
4. James Mizell	Westar Energy, Inc.	SPP	1, 3, 5, 6									
5. Ellen Watkins	Sunflower Electric Power Corporation	SPP	1									
6. Robert Rhodes	Southwest Power Pool	SPP	2									
7. Shannon Mickens	Southwest Power Pool	SPP	2									
11. Individual	Heather Bowden	EDP Renewables North America LLC					X					
12. Individual	Thomas Foltz	American Electric Power	X		X		X	X				
13. Individual	Jonathan Meyer	Idaho Power	X									
14. Individual	John Merrell	Tacoma Power	X		X	X	X	X				
15. Individual	Michelle D'Antuono	Ingleside Cogeneration LP/Occidental Energy Ventures Corp			X		X		X			
16. Individual	Venona Greaff	Occidental Chemical Corporation							X			
17. Individual	Michael Moltane	ITC	X									
18. Individual	Sonya Green-Sumpter	South Carolina Electric & Gas	X		X		X	X				
19. Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
20. Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
21. Individual	Maryclaire Yatsko	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
22. Individual	David Greyerbiehl	Consumers Energy Company			X	X	X					
23. Individual	Bill Temple	Northeast Utilities	X									
24. Individual	John Pearson/Matt Goldberg	ISO New England		X								

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The DGR SDT thanks all commenters for their comments and refers the reader to the summary response above.

Organization	Agree	Supporting Comments of "Entity Name"
Colorado Springs Utilities	Agree	Public Service Enterprise Group (PSEG)
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP
South Carolina Electric & Gas	Agree	
Colorado Springs Utilities		Public Service Enterprise Group (PSEG)

1. Do you agree with the revisions made in proposed PRC-004-2.1a(X) to clarify applicability of PRC-004-2.1a to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.

Summary Consideration: The DGR SDT thanks all commenters for their comments and refers the reader to the summary response above.

Organization	Yes or No	Question 1 Comment
EDP Renewables North America LLC	No	Requirement 2 and Requirement 3 should add "in response to electrical quantities."
Public Service Enterprise Group	No	The changes would create a reliability gap between I4 generators and I2 generators. It also violates Section 303 of the NERC Rules of Procedure, paragraph 1 that states: “Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage.” Presently, every generator at a site that exceeds 75 MVA is subject to the standard. All I2 generators, regardless of size, would remain subject to the standard, but all I4 generators would be exempt except at the point where their output aggregates to greater than 75 MVA. In addition, individual I2 greater than 20 MVA are subject to the standard, regardless of the aggregate output of generation at a common point of connection. We suggest changes to the added bullet in R2 and R3 to make the standard comparable for all resources (added language is CAPITALIZED):” For Misoperations occurring on the Protection Systems of individual [delete “dispersed power producing resources”] GENERATORS identified under INCLUSION I2 AND Inclusion I4 of the BES definition where the

Organization	Yes or No	Question 1 Comment
		Misoperations affected an aggregate nameplate rating of less than or equal to [delete "75"] 20 MVA of BES facilities, this requirement does not apply."
ISO New England	No	In R2 and R3, the words "or could have affected" were initially added but then they were deleted. Those words should not have been deleted or similar replacement language should be added. The PRC subteam had indicated to us that those words would be included. The deleted words addressed the concern we expressed during the comment period for the Dispersed Generation White Paper. Specifically, we stated that we do not agree with limiting the analysis requirement to a trip of greater than 75 MVA because that only accounts for very large occurrences that could be unusual. Smaller occurrences, however, may predict an unusual large occurrence that could impact reliability. Many of these wind turbine installations at different sites all use the same equipment and during a major disturbance reliability may be reduced by misoperations. The deleted words were in fact included in the "Standards Applicability Guidelines" that were circulated for comment but were ultimately not issued. Wording that indicates when misoperations occur on relays that are used in applications that ultimately represent over 75 MVA should be added back in.
Northeast Power Coordinating Council	Yes	
Arizona Public Service Co	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	

Organization	Yes or No	Question 1 Comment
Puget Sound Energy	Yes	
ACES Standards Collaborators	Yes	We agree with the changes. However, one additional change is necessary. “BES facilities” should be changed to the defined term “Facilities.” By definition Facilities would be limited to the BES and would appear to constitute the same meaning that is conveyed by “BES facilities.”
DTE Electric Co.	Yes	
SPP Standards Review Group	Yes	
American Electric Power	Yes	
Idaho Power	Yes	
Tacoma Power	Yes	
Ingleside Cogeneration LP/Occidental Energy Ventures Corp	Yes	Occidental Energy Ventures Corp. (OEVC) agrees that the scope of a Misoperation investigation should be limited to those Protection Systems affiliated with 75+ MVA aggregation points located within a dispersed generation facility. It makes no sense requiring a compulsory NERC-compliant investigation and report down to the windmill or solar panel level - unless somehow the aggregation point is affected. This is unlikely to be the case most of the time, and if every minimal incident is subject to PRC-004-2.1a(X), both the relay owner and CEA community could be overwhelmed with the volume of work required. This serves no useful reliability purpose.
Manitoba Hydro	Yes	
Seminole Electric Cooperative, Inc.	Yes	

Organization	Yes or No	Question 1 Comment
Consumers Energy Company	Yes	
Northeast Utilities	Yes	

2. Do you agree with the revisions made in proposed PRC-004-4 to clarify applicability of PRC-004-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes

Summary Consideration: The DGR SDT thanks all commenters for their comments and refers the reader to the summary response above.

Organization	Yes or No	Question 2 Comment
EDP Renewables North America LLC	No	Applicability (4.2.1.5) should include "in response to electrical quantities."
Public Service Enterprise Group	No	For the same reasons described in Q1 above, part 4.2.1.5 should have similar changes applied.
Seminole Electric Cooperative, Inc.	No	Seminole agrees with the specific revisions concerning only the changes to distributed generation, however, Seminole does not agree with the ongoing revisions through Project 2010-05.1 that are included in this revision, such as the owner of the BES interrupting device being required to initiate review in all scenarios as opposed to the entity that initiated the interrupting device's action. Therefore, Seminole must vote negative as this revision includes language from Project 2010-05.1 that Seminole does not find agreeable.

Organization	Yes or No	Question 2 Comment
ISO New England	No	See Question 1 response
Northeast Power Coordinating Council	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Puget Sound Energy	Yes	
ACES Standards Collaborators	Yes	When reviewing the red-line version of the standard comparing this version to the last posting, we can find no differences pertaining the portion of the standard dealing with dispersed generation resources. Comparing for changes would be much easier if all of the red-lines that do not pertain to this project were changed to black text especially considering PRC-004-3 was approved by the NERC Board of Trustees in their mid-August prior to the posting of this standard.
DTE Electric Co.	Yes	
SPP Standards Review Group	Yes	
American Electric Power	Yes	
Idaho Power	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 2 Comment
Ingleside Cogeneration LP/Occidental Energy Ventures Corp	Yes	OEVC agrees that the scope of a Misoperation investigation should be limited to those Protection Systems affiliated with 75+ MVA aggregation points located within a dispersed generation facility. It makes no sense requiring a compulsory NERC-compliant investigation and report down to the windmill or solar panel level - unless somehow the aggregation point is affected. This is unlikely to be the case most of the time, and if every minimal incident is subject to PRC-004-3, both the relay owner and CEA community could be overwhelmed with the volume of work required. This serves no useful reliability purpose.
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
Northeast Utilities	Yes	

3. **Do you have any additional comments to assist the DGR SDT in further developing its recommendations?**

Summary Consideration: The DGR SDT thanks all commenters for their comments and refers the reader to the summary response above.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	
Dominion	No	
DTE Electric Co.	No	
EDP Renewables North America LLC	No	

Organization	Yes or No	Question 3 Comment
American Electric Power	No	
Idaho Power	No	
Tacoma Power	No	
Manitoba Hydro	No	
Seminole Electric Cooperative, Inc.	No	
Northeast Utilities	No	
ISO New England	No	
MRO NERC Standards Review Forum	Yes	
Puget Sound Energy	Yes	In the proposed Applications and Guidelines for PRC-004-4: The section "Composite Protection System - Breaker Failure Example" reads "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." This example is inconsistent with #1 of the new proposed Misoperation Definition (Failure to Trip - During Fault), which reads "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." The example given above is NOT a

Organization	Yes or No	Question 3 Comment
		Misoperation, because the Composite Protection System operated correctly even with a failed trip coil (from what we understand of what is written).
ACES Standards Collaborators	Yes	The SDT should clarify what is meant by “affected.” Does this mean that amount of generation that was actually outaged as a result of the Misoperation? Or would this include an evaluation of the other potential Misoperations that could have occurred if the same conditions were experienced at other locations within the dispersed generation site? We believe that the answer should be the former rather than the latter. To make this clear, we suggest changing the word “affected” to “outaged” or, at least, providing an explanation in the technical/application guidelines section of the standard.
Ingleside Cogeneration LP/Occidental Energy Ventures Corp	Yes	OEVC is encouraged by the rapid progress that the DGR SDT has made in the development and approval of the first three priority standards. We appreciate the hard work and are hoping the project team will continue at the same rapid pace in the next grouping.
ITC	Yes	The Standard should define dispersed power producing resource. While in a practical sense this is a facility comprised of wind turbines or PV inverters, offering exclusions from Requirements based on an undefined criteria is not a good practice. R4 - ITC recommends removal of the sub-bullet under R4 excluding the generators identified through Inclusion I4. The exclusion using BES I4 is confusing and may conflict with existing standard VAR-001-4. A non-BES unit or several non-BES units combined together could have an impact on the BES and thus removing the generators from VAR-002-4 R4 solely based on Inclusion I4 may be affect reliability. Per VAR-001-4 R4, the TOP is required to specify criteria that will exempt generators from following a voltage or reactive power schedule and associated notification requirements. Therefore, ITC recommends that VAR-002-3 R4 should be reworded as “Unless exempted by the Transmission Operator, each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of

Organization	Yes or No	Question 3 Comment
		a change in reactive capability due to factors other than a status change described in Requirement 3”. The TOP can determine what notifications are necessary and be more specific depending on the needs of the system or individual facility. For example, a TOP exemption criteria may contain: “Dispersed power producing facilities are exempt from reactive capability change notifications less than 10% of the total aggregate lagging reactive capability as measured at the POI at nominal voltage”. TOPs typically will not want to receive individual turbine outage notifications; however, there may be instances where a dispersed power producing resource could lose an individual unit that may affect reliable operations (i.e. large individual units, near nuclear facility). In addition, the sub-bullet language in VAR-002-4 may be interpreted such that generators not in BES are exempt from reactive capability notifications and, in turn, exempt from following schedules which may be in conflict with VAR-001-4 and potentially impact the reliability of the BES. VAR-001-4 requires the TOP to determine the exemption criteria for generators and ITC recommends that VAR-002-4 be consistent with this practice as the TOP may require non-BES generators to follow a voltage or reactive power schedule based on the collective impact to the BES.
Public Service Enterprise Group	Yes	The SDT has not provided a technical rationale for its proposed changes but instead has hidden behind the I4 definition. As the SDT well knows, NERC standards may apply to Elements that are not included in the BES definition.
Consumers Energy Company	Yes	For this exclusion, the standard formatting was changed from the previous standards and revisions. Was this intentional and why? If so, are the other standards going to be revised similarly.
SPP Standards Review Group		We would like to thank the drafting team for taking into consideration our suggestions in reference to replacing the term ‘BPS’ with ‘BES’ in both(PRC-004-2.1a(X) and PRC-004-4) as well as including the new term ‘Composite Protection

Organization	Yes or No	Question 3 Comment
		System’ in PRC-004-4. We felt these suggestions would help maintain consistency with the current documentation and the BES Definition.

END OF REPORT

Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources
Recommended Applicability Changes to VAR-002-4

The Dispersed Generation Resources (DGR)[1] standards drafting team (SDT) thanks all commenters who submitted comments on the standards. Recommended applicability changes to VAR-002-4 and VAR-002-2b(X) were posted for a 45-day comment period from August 27, 2014 through October 16, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through an electronic comment form. There were 18 responses, including comments from approximately 88 different entities from approximately 63 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Please note that the Federal Energy Regulatory Commission (FERC) approved VAR-002-3 on August 1, 2014, and VAR-002-2b was retired effective at midnight on September 30, 2014. Therefore, the SDT will not post its recommended applicability changes to VAR-002-2b~~.~~

All comments submitted may be reviewed in their original format on the standard's project page.

This document contains the SDT's response to all industry comments received during this comment period. The SDT encourages commenters to review its responses to ensure all concerns have been addressed. The SDT notes that a significant majority of commenters agrees with the SDT's recommendations on this standard, but that some commenters expressed specific concerns. Some comments supporting the SDT's recommendations are discussed below but in most cases are not specifically addressed in this response. Also, several comments in response to specific questions are duplicated in other questions, and several commenters raise substantively the same concerns as others. Therefore, the SDT's consideration of all comments is addressed in this section in summary form, with duplicate comments treated as a single issue. Any comments made on another standard are addressed in the SDT's response to comments on that standard.

1. Summary Consideration

Based on the results from the recent comment and ballot period, it appears that industry overwhelmingly agrees with the SDT's recommendations to make applicability changes to account for

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably.

the unique characteristics of DGRs in the VAR-002 Reliability Standard. However, there are some disagreements among stakeholders and typographical errors contained in and illuminated by industry comments. The SDT has carefully reviewed and considered each stakeholder comment and has revised its recommendations where suggested changes are consistent with SDT intent and industry consensus. However, all recommended changes are non-substantive as contemplated by the NERC Standard Processes Manual and therefore do not require an additional ballot. The SDT's consideration of all comments follows.

2. General Comments

Industry identified a number of typographical and formatting errors in the posted recommendations to VAR-002. The DGR SDT has addressed each identified typographical and formatting error as appropriate in the posted redlined standard.

3. Recommended Applicability Changes to VAR-002

Several commenters suggested that there should either be a variance in recognition of the WECC regional standards VAR-002-WECC-1 and VAR-501-WECC-1 or an explanation as to how this continent-wide standard is or is not impacted by those regional standards given all contained requirements relative to actions required to be taken by the Generator Operator when the AVR or PSS is out of service.

The DGR SDT reviewed the Reliability Standards to determine those that would require revision, and determined that neither VAR-002-WECC-1 nor VAR-501-WECC-1 needed further action. As such, and as discussed in the White Paper, the DGR SDT did not recommend that the regions revise those standards, nor did the DGR SDT determine it was necessary to include the regional VAR standards in the DGR SDT-developed list of low-priority standards.

Furthermore, the DGR SDT maintains that addressing WECC regional standards VAR-002-WECC-1 and VAR-501-WECC-1 through a variance in a continent-wide standard is not technically justified, and modification of regional standards is beyond the scope of the DGR SDT.

At least one commenter questions including standard language in bullet format. The DGR SDT's use of the bullet format is consistent with guidance from NERC staff. In the absence of industry consensus or guidance from NERC staff that supports eliminating the bullet format in favor of another format, the DGR SDT elects to retain the bullet format.

At least one commenter believes the standard should define dispersed power producing resource.

The DGR SDT maintains that this issue is adequately addressed in the White Paper. The DGR SDT believes that the proposed language as it exists adequately describes the treatment of dispersed power producing resources, a position that is supported by clear industry consensus.

At least one commenter expressed concern that VAR-002 states non-applicability of the standard for dispersed generation resources identified through Inclusion I4 of the Bulk Electric System (BES) definition, and indicated that the bullet added to Requirement R3 part 3.1 exempts all I4 generators from reporting on their VAR capability status. The commenter suggested that the result was discriminatory to I2 generators and omits key data for TOPs, and will result in less ability for TOPs to correctly model their VAR supply. The commenter further stated that I4 generators are already obligated to comply with the standard without the proposed changes, and suggested that further explanation of the rational basis for the proposed changes from the DGR SDT should be provided that validates the changes proposed.

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources identified in Inclusion I4, the requirement that addresses reporting of changes in reactive capability should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. Instead, it should apply at the 75 MVA aggregate level. In addition, other Reliability Standards, such as proposed TOP-003, require the Generator Operator to provide real time data as directed by the TOP, and are more appropriately addressed through those Reliability Standards. Similarly, the SDT maintains that Footnote 5 is drafted such that individual generating unit transformers are subject to exception; however, the exception does not include the main generation facility transformer. Further, the SDT appreciates the commenters' concerns regarding modeling capability; however, as VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES, the SDT maintains that modeling issues are best addressed in the NERC MOD Standards.

At least one commenter questions whether the exception that is being proposed for Requirement R4 also should be applied to Requirement R3, reasoning that otherwise, the Generator Operator will be required to report status changes for AVRs or other voltage controlling devices for each individual generating unit of a DGR.

The DGR SDT understands that the generation facilities subject to Inclusion I4 of the BES definition can be comprised of individual generating units that are typically controlled by centralized voltage/reactive controllers that can be considered alternative voltage control devices as listed in Requirement R4. Additionally, there are generation facilities that perform this voltage/reactive control at the individual power producing resource. The DGR SDT has determined that a status change of these controllers should be reported regardless of which voltage/reactive control design is used at a facility, which explains why the exclusion was not extended to Requirement R3. The exclusion in Requirement

R4 was intended to exclude reporting of an individual generator at a dispersed generating facility coming offline as a change in reactive capability. For these reasons the DGR SDT respectfully declines to adopt the commenter's recommendation.

At least one commenter suggested adding the terms from footnotes in the standard to the NERC Glossary. Other commenters suggested revisions to, or elimination of, footnotes in the standard. The DGR SDT has carefully considered these suggestions and declines to adopt them at this time because they are either outside the scope of this project or are not technically justified.

At least one commenter does not agree with deleting the rationales used in the previous versions of the standard. The rationale information included in previous versions of the standard is available as appropriate in other associated documents, and the DGR SDT therefore respectfully declines to adopt the commenter's suggestion.

At least one commenter requests the DGR SDT revise either Requirement R4 or R5 regarding placement of exclusion language for consistency, noting that the Requirement R4 exclusion statement is a bulleted item within the requirement text, and that the Requirement R5 exclusion statement is a footnote at the bottom of the page.

The purpose of each item is unique with respect to the other, so the DGR SDT chose not to express the items in the same manner. The purpose of the bulleted item in Requirement R4 is to exclude individual generating resources from the Requirement R4 as appropriate. The purpose of the footnote in Requirement R5 is to clarify the applicability of that Requirement. For these reasons, the DGR SDT respectfully declines to adopt the commenter's suggestion.

Some commenters suggest modifications to the standard's Violation Severity Levels (VSLs). However, changing VSLs is outside the scope of this project.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[2]

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[2] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Jason Marshall	ACES Standards Collaborators	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
2.	Paul Jackson	Buckeye Power	RFC	3, 4, 5
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
4.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1, 5
5.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
6.	Matthew Caves	Western Farmers Electric Cooperative	SPP	1, 5
7.	John Shaver	Southwest Transmission Cooperative	WECC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

8.	Bob Solomon	Hoosier Energy	RFC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Randi Heise	Dominion Resources, Inc.	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randi Heise	Dominion	NPCC	6
2.	Mike Garton	Dominion	NPCC	5
3.	Louis Slade	Dominion	SERC	5, 6
4.	Larry Nash	Dominion	SERC	1, 3
5.	Connie Lowerq	Dominion	RFC	5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Kathleen Black	DTE Electric Co.			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Coop	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Ken Goldsmith	Alliant Energy	MRO	4
8.	Mamood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
9.	Marie Knox	MISO	MRO	2
10.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
11.	Randi Nyholm	Minnesota Power	MRO	1, 5
12.	Scott Nickels	Rochester Public Utilities	MRO	4
13.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
14.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	Guy Zito	Northeast Power Coordinating Council	X	X	X		X	X		X	X	X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	Ne York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority		5
23.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
24.	Peter Yost	Consolidated Edison Co, of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
6.	Group	Robert Rhodes	SPP Standards Review Group	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	John Boshears	City Utilities of Springfield	SPP	1, 4
3.	Jerry Bradshaw	City Utilities of Springfield	SPP	1, 4

4. Kevin Foflygen	City Utilities of Springfield	SPP	1, 4
5. Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
6. Bo Jones	Westar Energy	SPP	1, 3, 5, 6
7. Mike Kidwell	Empire District Electric	SPP	1, 3, 5
8. Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
9. Nick McCarty	Kansas City Power & Light	SPP	1, 3, 5, 6
10. Kyle McMenamin	Xcel Energy	SPP	1, 3, 5, 6
11. Shannon Mickens	Southwest Power Pool	SPP	2
12. Wes Mizell	Westar Energy	SPP	1, 3, 5, 6
13. James Nail	City of Independence, MO	SPP	3, 5
14. Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
15. J. Scott Williams	City Utilities of Springfield	SPP	1, 4

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment 1	2	3	4	5	6	7	8	9	10
7.	Individual	Janet Smith	Arizona Public Service Co	X		X		X	X				
8.	Individual	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
9.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
10.	Individual	Heather Bowden	EDP Renewables North America LLC					X					
11.	Individual	Timothy Brown	Idaho Power	X									
12.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
13.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP/Occidental Energy Ventures Corp.			X		X		X			
14.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
15.	Individual	Spencer Tacke	Modesto Irrigation District			X	X		X				
16.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
17.	Individual	Karin Schweitzer	Texas Reliability Entity										X
18.	Individual	Michael Moltane	International Transmission Company Holdings Corp	X									

1. **Do you agree with the revisions made in proposed VAR-002-4 to clarify applicability of VAR-002-3 to dispersed power producing resources included in the BES through Inclusion I4 of the BES definition? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The DGR SDT thanks all commenters for their comments and refers the reader to the summary response above.

Organization	Yes or No	Question 1 Comment
SPP Standards Review Group	No	Description of Current Draft - Language in this section indicates that VAR-002-3 '...was adopted by the NERC Board of Trustees in May 2014 and is pending regulatory approval'. Shouldn't this be revised to indicate that FERC has now approved VAR-002-3 and it will become effective on October 1, 2014? A similar statement is included in the Rationale Box appearing alongside the Introduction.R3 - Shouldn't the exception that is being proposed for Requirement R4, also be applied to Requirement R3? Otherwise, the Generator Operator will be required to report status changes for AVRs or other voltage controlling devices for each individual generating unit of a dispersed power producing resource.R4 - In the first line of the bullet under Requirement R4, insert 'Requirement' between 'in' and 'R4'.Rationale Box for Exclusion in Requirement R4 - Replace 'real time' with the officially recognized term 'Real-time' in the last line in the Rationale Box.M5 - To make Measure M5 consistent with the language in Requirement R5, delete 'transformers' following 'its step-up'.
Modesto Irrigation District	No	For both VAR-002 proposed modifications, I don't think we should state non-applicability of the Standard for dispersed generation resources identified through Inclusion I4 of the BES definition, as the new addition of "Rationale for Footnote 5" erroneously states (i.e., "as they are not used to

Organization	Yes or No	Question 1 Comment
		improve voltage performance at the point of interconnection", which is simply not true). Some technical reasons for including the smaller generating units are as follows:WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed.Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2018.Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the August 1996 outage, and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV.
Public Service Enterprise Group	No	VAR-002-2b(X)The bullet added to subpart 3.1 exempts ALL I4 generators from reporting on their VAR capability status. Not only is this discriminatory to I2 generators, it omits key data for TOPs required to maintain voltage via VAR supply. If the bullet was changed so that changes in AGGREGATE VAR capability for a facility that contains I4 generators was reported, that would be OK; but it is unacceptable as written.Footnote 5 in R4 is also unacceptable for two reasons. First, it is discriminatory to I2 generators. Second, the modeling of ALL transformers, which consume VARS, will result in less ability for TOPs to correctly model their VAR supply.We also point out that I4 generators are already obligated to

Organization	Yes or No	Question 1 Comment
		comply with the standard without the proposed changes, and no reliability argument has been offered by the SDT that validates the changes proposed.VAR-002-4The same comments made for VAR-002-2b(X) apply, except that the bullet is in R4 and footnote 5 is in R5. While this standard is not effective, its predecessor, as discussed previously, does require I4 generators to meet the same requirements. No reliability argument has been provided by the SDT to support the change.
Colorado Springs Utilities	No	We Support the Comments of - Public Service Enterprise Group (PSEG).
Dominion Resources, Inc.	Yes	Dominion supports the revisions to R4 and R5 in support of clarity.
Ingleside Cogeneration LP/Occidental Energy Ventures Corp.	Yes	Occidental Energy Ventures Corp. agrees that the scope of R3.1 and R4 has been appropriately modified to capture the applicable AVRs, PSSs, and transformers located within a dispersed generation facility. There is no good reason to apply BES-level voltage and reactive requirements to individual windmills or solar panels - unless somehow a significant aggregation point is affected. This is unlikely to be the case most of the time, and if every minimal incident is subject to VAR-002-4, both the relay owner and CEA community could be overwhelmed.
ACES Standards Collaborators	Yes	We agree with the changes.
DTE Electric Co.	Yes	
MRO NERC Standards Review Forum	Yes	
Arizona Public Service Co	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 1 Comment
EDP Renewables North America LLC	Yes	
Idaho Power	Yes	
Manitoba Hydro	Yes	
Texas Reliability Entity	Yes	

2. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?.

Summary Consideration: The DGR SDT thanks all commenters for their comments and refers the reader to the summary response above.

Organization	Yes or No	Question 2 Comment
DTE Electric Co.	No	
SPP Standards Review Group	No	
Arizona Public Service Co	No	
American Electric Power	No	
Idaho Power	No	
Ingleside Cogeneration LP/Occidental Energy Ventures Corp.	No	
Manitoba Hydro	No	
Modesto Irrigation District	No	
Dominion Resources, Inc.	Yes	Comments: Dominion believes there should either be a variance in recognition of the WECC regional standards VAR-002-WECC-1 and VAR-501-WECC-1 in this standard or an explanation as to how this continent-wide standard is or is not impacted by those regional standards given all contained requirements relative to actions required to be taken by the Generator Operator when the AVR or PSS is out of service.We suggest the SDT review the current style guide regarding whether to use sub-parts (3.1, 4.1,

Organization	Yes or No	Question 2 Comment
		etc) as opposed to using bullets. Having sub-parts identified make identification of information to communicate.
Public Service Enterprise Group	Yes	Describe the reliability impacts of proposed changes
Northeast Power Coordinating Council	Yes	For VAR-002-4, the Drafting Team should consider adding start-up and shutdown from footnotes 1 and 2 to the NERC Glossary. For footnote 2 on page 5 suggest replacing “prepared” with “intended”. Because the Rationale Boxes stay with the standard after approval, the Drafting Team should consider moving the information in the footnotes to the appropriate Rationale Boxes, and deleting the footnotes.
Indiana Municipal Power Agency	Yes	IMPA does not agree with the deletion of the rationales for each requirement on pages 11 and 12. These rationales are used for the previous version of the standard and are still needed in the standard. The additions made by the dispersed generation SDT should not have changed the basis for these rationales. IMPA is fine with adding to them but not deleting all of them.
ACES Standards Collaborators	Yes	The language adopted in the bullet under Part 3.1 of VAR-002-2b(X) is inconsistent with the August 10, 2009 informational filing NERC submitted to FERC regarding how NERC would begin using a new approach to assign VRFs and VSLs to the main requirement only. In this filing, NERC stated that they would no longer refer to “components” or “sub-parts” of requirements as sub-requirements. Rather, they would be numbered or bulleted lists. Thus, the Requirement R3.1 reference in the bullet under Part 3.1 is inconsistent and should be labeled as Part 3.1.
Texas Reliability Entity	Yes	VAR-002-41)Requirements R4 and R5: Texas Reliability Entity, Inc. (Texas RE) requests the SDT make a change to either R4 or R5 regarding placement of exclusion language for consistency. In Requirement R4 the exclusion statement is a bulleted item within the requirement text. In Requirement R5 the exclusion statement is a footnote at the bottom of the page. Texas RE suggests that moving the exclusion language in the

Organization	Yes or No	Question 2 Comment
		requirement language of Requirement R5 is preferable to moving Requirement R4 exclusion language to a footnote. 2)Requirement R5 VSLs: Texas RE requests the SDT consider changing Requirement R5 VSL Levels as follows: Moderate "...one of the types of data..."High "...two of the types of data..."Severe "...all of the types of data..."Changing the VSL language in this manner is consistent with VAR-002-2b(x), Requirement R4 VSL levels. VAR-002-2b(X)Texas RE suggests a minor change to the Requirement R4 Severe VSL: replace the word "any" with "all" in the first statement. As written, it would appear that a responsible entity failing to provide any one of the types of data would result in a severe VSL instead of the failure to provide all of the types of data. This change would result in the following Severe VSL language: "The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner all of the types of data as specified in R4.1.1 and R 4.1.2 and 4.1.3 and 4.1.4..."
Colorado Springs Utilities	Yes	We Support the Comments of - Public Service Enterprise Group (PSEG).
International Transmission Company Holdings Corp	Yes	The Standard should define dispersed power producing resource. While in a practical sense this is a facility comprised of wind turbines or PV inverters, offering exclusions from Requirements based on an undefined criteria is not a good practice. R4 – ITC recommends removal of the sub-bullet under R4 excluding the generators identified through Inclusion I4. The exclusion using BES I4 is confusing and may conflict with existing standard VAR-001-4. A non-BES unit or several non-BES units combined together could have an impact on the BES and thus removing the generators from VAR-002-4 R4 solely based on Inclusion I4 may be affect reliability. Per VAR-001-4 R4, the TOP is required to specify criteria that will exempt generators from following a voltage or reactive power schedule and associated notification requirements. Therefore, ITC recommends that VAR-002-3 R4 should be reworded as "Unless exempted by the Transmission Operator, each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement 3". The

Organization	Yes or No	Question 2 Comment
		TOP can determine what notifications are necessary and be more specific depending on the needs of the system or individual facility. For example, a TOP exemption criteria may contain: “Dispersed power producing facilities are exempt from reactive capability change notifications less than 10% of the total aggregate lagging reactive capability as measured at the POI at nominal voltage”. TOPs typically will not want to receive individual turbine outage notifications; however, there may be instances where a dispersed power producing resource could lose an individual unit that may affect reliable operations (i.e. large individual units, near nuclear facility). In addition, the sub-bullet language in VAR-002-4 may be interpreted such that generators not in BES are exempt from reactive capability notifications and, in turn, exempt from following schedules which may be in conflict with VAR-001-4 and potentially impact the reliability of the BES. VAR-001-4 requires the TOP to determine the exemption criteria for generators and ITC recommends that VAR-002-4 be consistent with this practice as the TOP may require non-BES generators to follow a voltage or reactive power schedule based on the collective impact to the BES.
MRO NERC Standards Review Forum	Yes	
EDP Renewables North America LLC	Yes	

END OF REPORT

Standard Development Timeline

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Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.
3. 45-day formal comment period with initial ballot conducted July 10, 2014 through August 26, 2014.
4. Posted for additional comment and ballot September 5, 2014 through October 22, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. A subsequent version of PRC-004, i.e., PRC-004-3, also is under active standard development. Depending on the timing of regulatory approval, this interim version, which had been labeled PRC-004-2.1a(X) and is now labeled PRC-004-2.1(i)a for final balloting purposes, may be filed for regulatory approval. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT adoption	November 2015

When this standard has received ballot approval, the text boxes within the Applicability section of the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1a(X)
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
   - **4.1.** Transmission Owner.
   - **4.2.** Distribution Provider that owns a transmission Protection System.
   - **4.3.** Generator Owner.
5. **Effective Date:** See the Implementation Plan for this Standard.

Rationale for Introduction: The only revisions made to this version of PRC-004-2.1(i)a are revisions to Requirements R2 and R3 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.

This version is labeled PRC-004-2.1(i)a for balloting purposes. The 'i' indicates that a version number will be applied at a later time, because multiple versions of PRC-004 have been in development. The 'i' designation reflects the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. Depending on the timing of approvals of other versions and other factors, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

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, Requirement R2 and Requirement R3 reflect the threshold consistent with the revised BES definition. See paragraph 20 of FERC Order Approving Revised Definition in Docket No. RD14-2-000. The intent of Requirement R2 and Requirement R3 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

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

- For Misoperations occurring on the 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, this requirement does not apply.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. 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. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the Board of Trustees	
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	2011	of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
TBD (balloted as 2.1(i)a)	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of Requirements to BES dispersed power producing resources

Appendix 1[1]

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

Standard Development Timeline

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Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. A subsequent version of PRC-004, i.e., PRC-004-3, also is under active standard development. Depending on the timing of regulatory approval, this interim version, which had~~s~~ been labeled PRC-004-2.1a(X) and is now labeled PRC-004-2.1(i)a for final balloting purposes, may be filed for regulatory approval. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
~~45-day Additional Formal Comment Period with Additional Ballot (if necessary)~~	~~September – October 2014~~
Final ballot	October 2014
BOT adoption	November 2015

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2. **Number:** PRC-004-2.1a(X)
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4. **Applicability**
   - **4.1.** Transmission Owner.
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5. **Effective Date:** See the I~~i~~mplementation P~~p~~lan for this Standard.

Rationale for Introduction: The only revisions made to this version of PRC-004-2.1(i)a~~(X)~~ are revisions to Requirements R2 and R3 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.

This version is labeled PRC-004-2.1(i)a~~(X)~~ for balloting purposes. The 'i~~X~~' indicates that a version number will be applied at a later time, because multiple versions of PRC-004 have been in development. The 'i~~X~~' designation reflects the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. Depending on the timing of approvals of other versions and other factors, NERC may file this interim version to provide regulatory certainty for entities as the revised BES definition is implemented.

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B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

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D. Compliance

1. Compliance Monitoring Process

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1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

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Self-Certifications

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2. Violation Severity Levels (no changes)

E. Regional Differences

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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. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
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   - **4.1.** Transmission Owner.
   - **4.2.** Distribution Provider that owns a transmission Protection System.
   - **4.3.** Generator Owner.
5. ~~**(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.~~ **Effective Date:** See the Implementation Plan for this Standard.

Rationale for Introduction: The only revisions made to this version of PRC-004-2.1(i)a are revisions to Requirements R2 and R3 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.

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1.1. Compliance Enforcement Authority

~~Regional Entity.~~

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Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

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2. Violation Severity Levels (no changes)

E. Regional Differences

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[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.
3. 45-day formal comment period with initial ballot conducted July 10, 2014 through August 26, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. The currently effective version of PRC-004, i.e., PRC-004-2.1a, also is under active standard development. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT adoption	November 2014

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.	01/20/06

		Changed “Timeframe” to “Time Frame” in item D, 1.2.	
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by NERC Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC’s Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add “…and generator interconnection Facility…”	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by NERC Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	TBD	Applicability revised to clarify application of Requirements to BES dispersed power producing resources	Standard revised in Project 2014-01

When this standard has received ballot approval, the rationale boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. Title: **Protection System Misoperation Identification and Correction**

2. Number: PRC-004-4

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.[1]

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.

Rationale for Introduction: The only revisions made to this version of PRC-004 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.

The DGR version of this standard had been labeled PRC-004-4 for balloting purposes. The 'X' had indicated that a version number would be applied at a later time, because multiple versions of PRC-004 were in development at the time of the previous posting. The 'X' designation reflected the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. However, PRC-004-3 was approved by the NERC Board of Trustees on August 14, 2014, so this version has been designated PRC-004-4 to indicate that this version is the successor version.

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

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.

5. Background:

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- 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.
- 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).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed

as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

6. Effective Dates:

See the Implementation Plan for this Standard.

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
R1	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
R3	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
R4	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
R5	Operations Planning, Long-Term Planning	Medium	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. OR (See next page)	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. OR (See next page)	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. OR (See next page)	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. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

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.[2]

[2] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] 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*[4]; 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*[5] 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[6]." 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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[3] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[4] "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

[5] "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

[6] "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.

Example7c: 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*[7] 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.

> **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.

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

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.[8]

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.

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*

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

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).

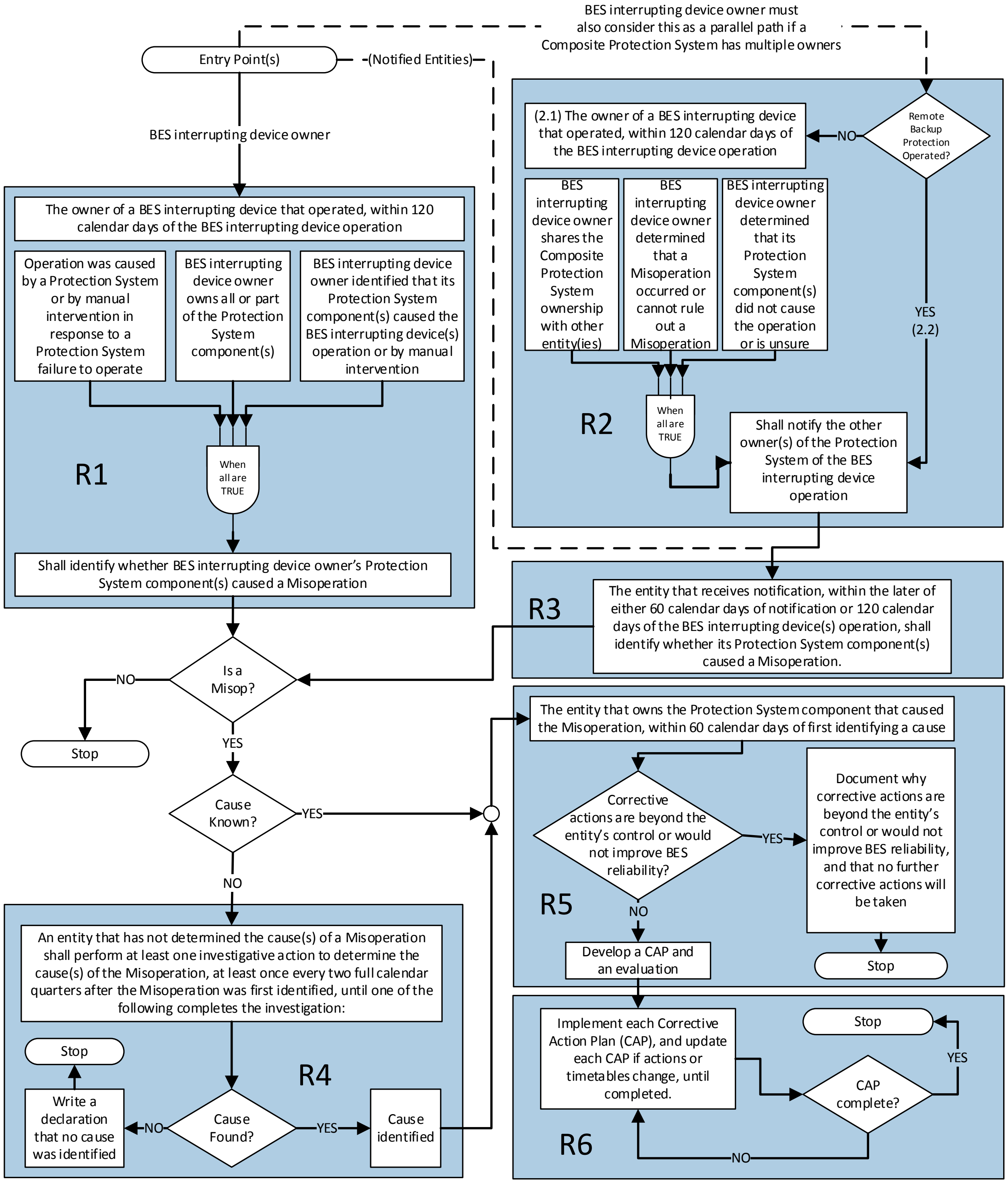
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance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



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.
3. 45-day formal comment period with initial ballot conducted July 10, 2014 through August 26, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. The currently effective version of PRC-004, i.e., PRC-004-2.1a, also is under active standard development. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
~~45-day Additional Formal Comment Period with Additional Ballot (if necessary)~~	~~September – October 2014~~
Final ballot	October 2014
BOT adoption	November 201<u>4</u>~~5~~

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 (—).”	01/20/06

		2. Added "periods" to items where appropriate. Changed "Timeframe" to "Time Frame" in item D, 1.2.	
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by NERC Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by NERC Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	TBD	Applicability revised to clarify application of Requirements to BES dispersed power producing resources	Standard revised in Project 2014-01

When this standard has received ballot approval, the rationale boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**
2. **Number:** PRC-004-4
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.[1]

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.

Rationale for Introduction: The only revisions made to this version of PRC-004 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.

The DGR version of this standard had been labeled PRC-004-4 for balloting purposes. The ‘X’ had indicated that a version number would be applied at a later time, because multiple versions of PRC-004 were in development at the time of the previous posting. The ‘X’ designation reflected the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. However, PRC-004-3 was approved by the NERC Board of Trustees on August 14, 2014, so this version has been designated PRC-004-4 to indicate that this version is the successor version.

[1] For additional information and examples, see the “Non-Protective Functions” and “Control Functions” sections in the Application Guidelines.

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.

5. Background:

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- 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.
- 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).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed

as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

6. Effective Dates:

See the I~~i~~mplementation P~~p~~lan for this Standard.

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
R1	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
R3	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
R4	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
R5	Operations Planning, Long-Term Planning	Medium	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. OR (See next page)	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. OR (See next page)	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. OR (See next page)	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. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

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.[2]

[2] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] 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*[4]; 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*[5] 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[6]." 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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[3] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[4] "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

[5] "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

[6] "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.

Example7c: 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*[7] 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.

> **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.

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

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.[8]

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.

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*

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

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).

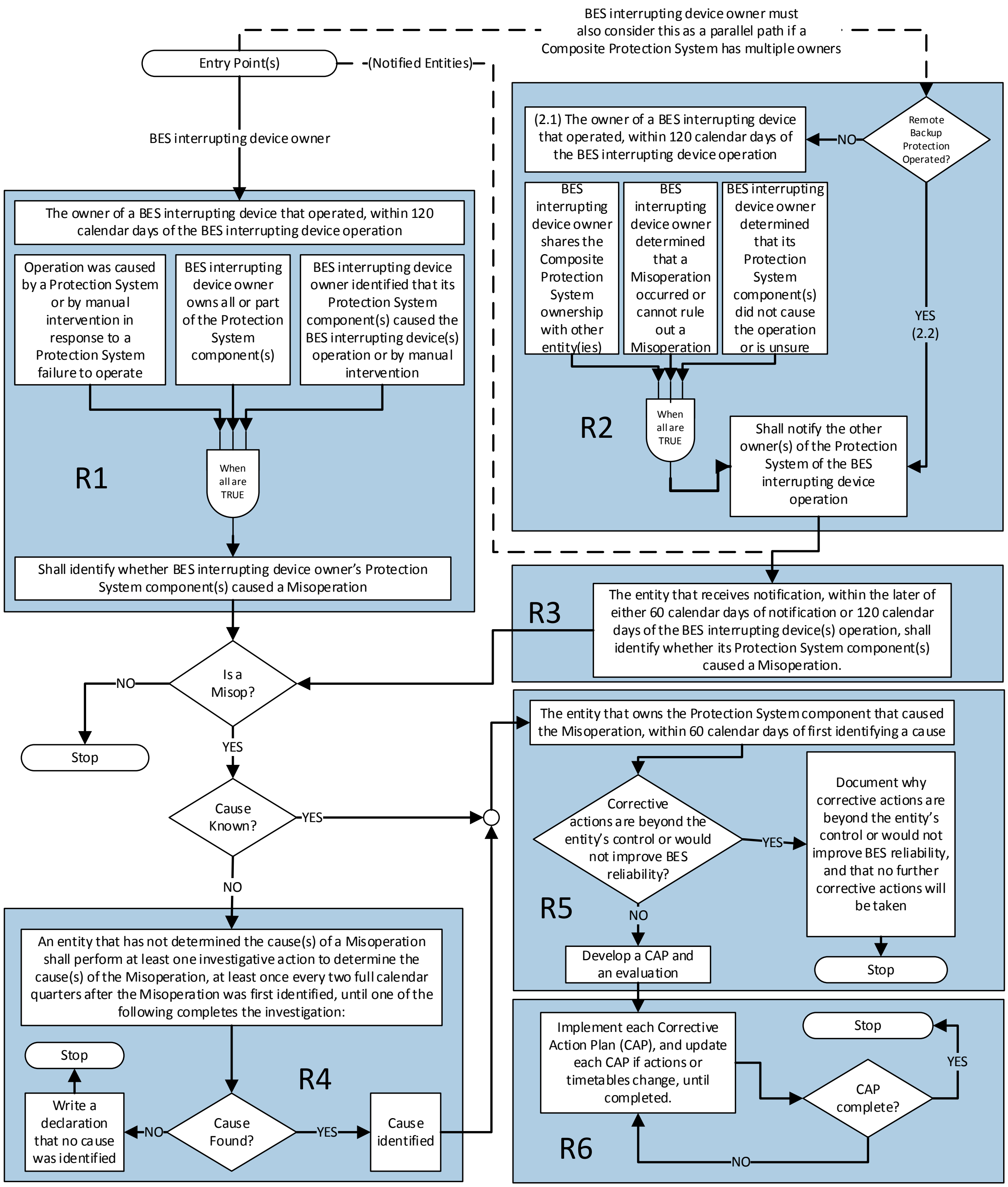
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance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



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on July 1, 2014.
3. 45-day formal comment period with initial ballot conducted July 10, 2014 through August 26, 2014.

Description of Current Draft

This version of PRC-004 contains applicability revisions to the Standard intended to clarify application of the Requirements to Bulk Electric System (BES) dispersed power producing resources. The currently effective version of PRC-004, i.e., PRC-004-2.1a, also is under active standard development. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the Requirements of PRC-004 to dispersed power producing resources.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT adoption	November 2014

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.	01/20/06

		Changed "Timeframe" to "Time Frame" in item D, 1.2.	
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by NERC Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by NERC Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	TBD	Applicability revised to clarify application of Requirements to BES dispersed power producing resources	Standard revised in Project 2014-01

When this standard has received ballot approval, the rationale boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

Rationale for Introduction: The only revisions made to this version of PRC-004 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.

The DGR version of this standard had been labeled PRC-004-4 for balloting purposes. The 'X' had indicated that a version number would be applied at a later time, because multiple versions of PRC-004 were in development at the time of the previous posting. The 'X' designation reflected the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. However, PRC-004-3 was approved by the NERC Board of Trustees on August 14, 2014, so this version has been designated PRC-004-4 to indicate that this version is the successor version.

1. **Title:** **Protection System Misoperation Identification and Correction**
2. **Number:** PRC-004-~~3~~4
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.[1]

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.

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

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.

5. **Background**:

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- 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.
- 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).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed

as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

6. Effective Dates:

~~The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable~~

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

See the Implementation Plan for this Standard.

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, ~~Disturbance Monitoring Equipment (~~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, ~~Disturbance Monitoring Equipment (DME)~~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
R1	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
R3	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
R4	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
R5	Operations Planning, Long-Term Planning	Medium	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. OR (See next page)	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. OR (See next page)	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. OR (See next page)	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. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

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.[2]

~~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.~~ ~~Changed "Timeframe" to "Time Frame" in item D, 1.2.~~	~~01/20/06~~
~~2~~		~~Modified to address Order No. 693 Directives contained in paragraph 1469.~~	~~Revised~~

[2] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

~~2~~	~~August 5, 2010~~	~~Adopted by NERC Board of Trustees~~	
~~1a~~	~~February 17, 2011~~	~~Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers~~	~~Project 2009-17 interpretation~~
~~1a~~	~~February 17, 2011~~	~~Adopted by the Board of Trustees~~	
~~1a~~	~~September 26, 2011~~	~~FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)~~	
~~2a~~	~~September 26, 2011~~	~~Appended FERC-approved interpretation of R1 and R3 to version 2~~	
~~2.1a~~		~~Errata change: Edited R2 to add "…and generator interconnection Facility…"~~	~~Revision under Project 2010-07~~
~~2.1a~~	~~February 9, 2012~~	~~Errata change adopted by the Board of Trustees~~	
~~2.1a~~	~~September 19, 2013~~	~~FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).~~	
~~3~~	~~August 14, 2014~~	~~Adopted by Board of Trustees~~	~~Revision under Project 2010-05.1~~

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] 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*[4]; 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*[5] 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[6]." 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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3 http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

4 "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

5 "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

6 "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.

> **Example7c:** 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 ~~Disturbance Monitoring Equipment (~~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*[7] 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.

> **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

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

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.[8]

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.

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: 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).

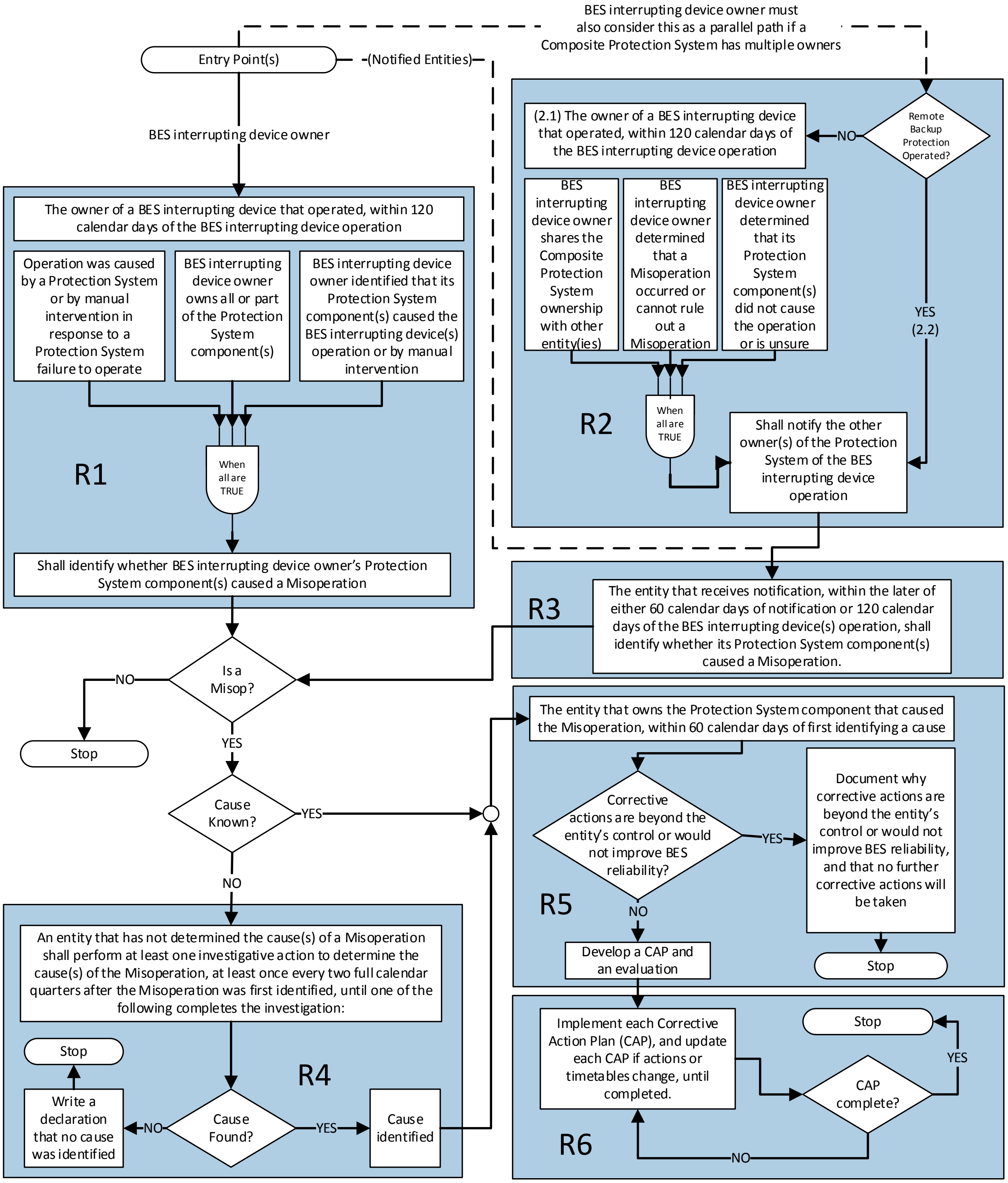
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance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

~~Rationale for Applicability:~~

~~Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded in this standard because they are planned to be handled in the second phase of this project.~~

~~Rationale for R1:~~

~~This Requirement ensures that entities review those Protection System operations meeting the circumstances in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner is assigned the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed.~~

~~Rationale for R2:~~

~~Part 2.1 ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System. The phrase "owner(s) that share Misoperation identification responsibility" allows entities to notify the specific other owners that will actually review the operation to determine if a Misoperation occurred. Part 2.2 ensures that the Protection System owner(s) for which backup protection was provided receives notification, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that Part 2.1, 2.2, or both are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.~~

~~Rationale for R3:~~

~~When an entity receives notification of a Protection System operation by the BES interrupting device owner, the other Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.~~

~~**Rationale for R4:**~~

~~If a Misoperation cause is not identified within the time period established by Requirements R1 or R3 (i.e., 120 calendar days), the Protection System component owner must demonstrate investigative actions toward identifying the cause(s). Performing at least one action every two full calendar quarters from first identifying the Misoperation encourages periodic focus on finding the cause of the Misoperation.~~

~~**Rationale for R5:**~~

~~A formal CAP is a proven tool for resolving and reducing the possibility of reoccurrence of operational problems. A time period of 60 calendar days is based on industry experience and operational coordination time needed for considering such things as alternative solutions, coordination of resources, or development of a schedule. When the cause of a Misoperation is identified, a CAP will generally be developed. An evaluation of the CAP's applicability to the entity's other Protection Systems including other locations helps identify similar problems, the potential for Misoperation occurrences in other Protection Systems, common mode failure, design problems, etc.~~
~~In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, a statement documenting the reasons for taking no corrective actions is essential for future reference and for justifying the absence of a CAP.~~

~~**Rationale for R6:**~~

~~Each CAP must accomplish all identified objectives to be complete. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion.~~

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-3. The standard was approved by FERC and became effective October 1, 2014. The intent of the revisions is to clarify application of Requirements R4 and R5 to Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
Board of Trustees adoption	November 2014

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.	Revised
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised
3	5/7/2014	Adopted by NERC Board of Trustees	
3	8/1/2014	Approved by FERC in docket RD14-11-000	
4	8/27/2014	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised

Definitions of Terms Used in the Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

When this standard has received ballot approval, the text boxes within the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Generator Operator
   - **4.2.** Generator Owner
5. **Effective Dates**

   See Implementation Plan.

The only revisions made to this version of VAR-002 are revisions to Requirements R4 and R5, 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.

The revisions to the two Requirements were made to VAR-002-3, which was approved by its ballot pool and adopted by the NERC Board in May 2014, and was subsequently approved by FERC and became effective October 1, 2014.

B. Requirements and Measures

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within each generating Facility's capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in Requirement R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for Exclusion in Requirement R4:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide Real-time data as directed by the TOP.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

5.1. For generator step-up and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

Rationale for Exclusion in Requirement R5:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR-002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

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 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-3. The standard was approved by FERC and became effective October 1, 2014. The intent of the revisions is to clarify application of Requirements R4 and R5 to Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
Board of Trustees adoption	November 2014

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.	Revised
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised
3	5/7/2014	Adopted by NERC Board of Trustees	
3	8/1/2014	Approved by FERC in docket RD14-11-000	
4	8/27/2014	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised

Definitions of Terms Used in the Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

When this standard has received ballot approval, the text boxes within the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Generator Operator
   - **4.2.** Generator Owner
5. **Effective Dates**

   See Implementation Plan.

The only revisions made to this version of VAR-002 are revisions to Requirements R4 and R5, 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.

The revisions to the two Requirements were made to VAR-002-3, which was approved by its ballot pool and adopted by the NERC Board in May 2014, and was subsequently approved by FERC and became effective ~~September 30~~October 1, 2014.

B. Requirements and Measures

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within each generating Facility's capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive

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[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in Requirement R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for Exclusion in Requirement R4: VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide Real-time data as directed by the TOP.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

5.1. For generator step-up and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

Rationale for Exclusion in Requirement R5: The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR-002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up ~~transformers~~ and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

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 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.

Description of Current Draft

The Project 2014-01 Dispersed Power Producing Resources drafting team is posting minor applicability revisions to VAR-002-3. The standard was approved by FERC and became effective October 1, 2014. The intent of the revisions is to clarify application of Requirements R4 and R5 to Bulk Electric Systems (BES) dispersed power producing resources included in the BES though Inclusion I4 of the BES definition.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
Board of Trustees adoption	November 2014

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.	Revised
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised
3	5/7/2014	Adopted by NERC Board of Trustees	
3	8/1/2014	Approved by FERC in docket RD14-11-000	
4	8/27/2014	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised

Definitions of Terms Used in the Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

When this standard has received ballot approval, the text boxes within the Standard will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-~~3~~4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Generator Operator
   - **4.2.** Generator Owner

The only revisions made to this version of VAR-002 are revisions to Requirements R4 and R5, 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.

The revisions to the two Requirements were made to VAR-002-3, which was approved by its ballot pool and adopted by the NERC Board in May 2014, and was subsequently approved by FERC and became effective October 1, 2014.

5. **Effective Dates**

~~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, VAR-002-3 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.~~

See Implementation Plan.

B. Requirements and Measures

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up~~,[1] shutdown,[2]~~,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule~~[3]~~[3] (within each generating Facility's capabilities[4]~~)~~[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the

~~[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.~~

~~[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.~~

~~[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.~~

~~[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.~~

generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

~~2.1.~~2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

~~2.2.~~2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in Requirement R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for Exclusion in Requirement R4:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide Real-time data as directed by the TOP.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

5.1. For generator step-up ~~transformers~~ and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

Rationale for Exclusion in Requirement R5:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR-002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up ~~transformers~~ and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

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 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications. ~~OR~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~1~~	~~5/1/2006~~	~~Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.~~	~~July 5, 2006~~
~~1a~~	~~12/19/2007~~	~~Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007~~	~~Revised~~
~~1a~~	~~1/16/2007~~	~~In Section A.2., Added "a" to end of standard number.~~ ~~Section F: added "1."; and added date.~~	~~Errata~~
~~1.1a~~	~~10/29/2008~~	~~BOT adopted errata changes; updated version number to "1.1a"~~	~~Errata~~
~~1.1b~~	~~3/3/2009~~	~~Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009~~	~~Revised~~
~~2b~~	~~8/16/2012~~	~~Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b. Adopted by Board of Trustees.~~	~~Revised~~
~~2b~~	~~4/16/2013~~	~~FERC Order issued approving VAR-002-2b~~	
~~3~~	~~5/6/2014~~	~~Adopted by the NERC Board of Trustees~~	
~~3~~	~~8/1/2014~~	~~FERC issued letter order approving VAR-002-3~~	

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:**~~

~~This requirement has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in either voltage controlling mode or the mode instructed by the TOP. However, the requirement has been modified to allow for testing, and the measure has been updated to include some of the evidence that can be used for compliance purposes.~~

~~**Rationale for R2:**~~

~~Requirement R2 details how a Generator Operator (GOP) operates its generator(s) to provide voltage support and when the GOP is expected to notify the Transmission Operator (TOP). In an effort to remove prescriptive notification requirements for the entire continent, the VAR-002-3 standard drafting team (SDT) opted to allow each TOP to determine the notification requirements for each of its respective GOPs based on system requirements. Additionally, a new Part 2.3 has been added to detail that each GOP may monitor voltage by using its existing facility equipment.~~

~~Conversion Methodology: There are many ways to convert the voltage schedule from one voltage level to another. Some entities may choose to develop voltage regulation curves for their transformers; others may choose to do a straight ratio conversion; others may choose an entirely different methodology. All of these methods have technical challenges, but the studies performed by the TOP, which consider N-1 and credible N-2 contingencies, should compensate for the error introduced by these methodologies, and the TOP possesses the authority to direct the GOP to modify its output if its performance is not satisfactory. During a significant system event, such as a voltage collapse, even a generation unit in automatic voltage control that controls based on the low-side of the generator step-up transformer should see the event on the low-side of the generator step-up transformer and respond accordingly.~~

~~Voltage Schedule Tolerances: The bandwidth that accompanies the voltage target in a voltage schedule should reflect the anticipated fluctuation in voltage at the GOP'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 GOP's AVR control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.~~

~~**Rationale for R3:**~~

~~This requirement has been modified to limit the notifications required when an AVR goes out of service and quickly comes back in service. Notifications of this type of status change provide little to no benefit to reliability. Thirty (30) minutes have been built into the requirement to allow a GOP time to resolve an issue before having to notify the TOP of a status change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change.~~

~~**Rationale for R4:**~~

~~This requirement has been bifurcated from the prior version VAR-002-2b Requirement R3. This requirement allows GOPs to report reactive capability changes after they are made aware of the change. The current standard requires notification as soon as the change occurs, but many GOPs are not aware of a reactive capability change until it has taken place.~~

~~**Rationale for R5:**~~

~~**Application Guidelines**~~

Application Guidelines

~~This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected. The prior version of VAR-002-2b, Requirement R4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed. The percentage information was not needed because the tap settings, ranges and impedance are required. Those inputs can be used to calculate the step-change percentage if needed.~~

~~**Rationale for R6:**~~

~~This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected.~~

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Dispersed Generation Resources
PRC-004-2.1a(X)

The standard version number currently include an (X) to indicate the version numbering will be updated. PRC-004 has been substantively revised in Project 2010-05.1 concurrently with these revisions that address applicability to dispersed generation resources in this project. Depending on factors such as the timing of respective approvals in each project, NERC will assign the appropriate version number prior to BOT adoption.

Standards Involved
Approval:

- PRC-004-2.1a(X) – Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-2.1a – Protection System Misoperation Identification and Correction

Prerequisite Approvals:
N/A

Background
In light of the adoption of a revised Bulk Electric System definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised Bulk Electric System definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

General Considerations
PRC-004-2.1a(X) is proposed for approval to align the applicability section of PRC-004-2.1a with the revised definition of Bulk Electric System. Given the timing of concurrent standards development of PRC projects, PRC-004-2.1a may already be retired pursuant to an Implementation Plan of a successor version of PRC-004 by the time the revised definition of Bulk Electric System becomes effective for all entities. If this occurs, PRC-004-2.1a(X) will not go into effect.

Effective Date
PRC-004-2.1a(X) shall become effective immediately after 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.

Retirement of Existing Standards:

The existing standard, PRC-004-2.1a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-2.1a(X).

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Implementation Plan

Dispersed Generation Resources
PRC-004-4

Standards Involved

Approval:

- PRC-004-4 – Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-3 – Protection System Misoperation Identification and Correction

Prerequisite Approvals:

- PRC-004-3 – Protection System Misoperation Identification and Correction[1]

Background

In light of the adoption of a revised Bulk Electric System definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised Bulk Electric System definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

General Considerations

PRC-004-4 is proposed for approval to align the applicability section of PRC-004-3 with the revised definition of the Bulk Electric System. The intent of the SDT was to allow for flexibility of the PRC-004 applicability section regardless of the version that is currently in effect when an applicable governmental authority acts on the PRC-004-3 filing. Currently, PRC-004-2.1a is in effect as PRC-004-3 (developed in Project 2010-05.1) is pending regulatory approval. Depending on the timing of approvals for various versions of PRC-004, PRC-004-2.1a may still be in effect at the time the revised definition of Bulk Electric System becomes effective for all entities. If this occurs, PRC-004-2.1a(X) will go into effect and PRC-004-4 shall go into effect after the technical revisions developed in Project 2010-05.1 are approved by applicable regulators, or as otherwise provided for in jurisdictions that do not require regulatory approvals.

[1] PRC-004-3 was adopted by the NERC Board of Trustees on August 18, 2014.

Effective Date

PRC-004-4 shall become effective either immediately after 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, or 12 months following the approval of PRC-004-3, whichever is later. Where approval by an applicable governmental authority is not required, the standard shall become effective either 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, or 12 months following the approval of PRC-004-3, whichever is later.

Retirement of Existing Standards:

The existing standard, PRC-004-3, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-4.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Implementation Plan

Dispersed Generation Resources
VAR-002-4

Standards Involved
Approval:

- VAR-002-4 – Generator Operation for Maintaining Network Voltage Schedules

Retirement or Supersede:

- VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals:
N/A

Background:
In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including VAR-002, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

Effective Date
VAR-002-4 shall become effective on the later of the effective date of VAR-002-3, or the date the VAR-002-4 is approved by an applicable government 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.

Retirement of Existing Standards:
Approved VAR-002-3 shall be retired at midnight of the day immediately prior to the effective date of VAR-002-4.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation		
Date Submitted:	10/1/2013		
SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
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. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard.

PRC-005-2

Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply.

FAC-008-3

For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information
Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels. **PRC-023-3/PRC-025-1** In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements. **PRC-004-2** There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above. **VAR-002-2** Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard. **General review of IROs, MODs, PRCs, TOPs** IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

Reliability Functions		
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Final Ballots Now Open through November 6, 2014

Now Available

Final ballots for the **Standards Applicability for Dispersed Generation Resources Reliability** are open through **8 p.m. Eastern, Thursday, November 6, 2014.**

The final ballots are as follows:

- PRC-004-2.1(i)a and PRC-004-4 - Protection System Misoperation Identification and Correction
- VAR-002-4 - Generator Operation for Maintaining Network Voltage Schedules

Background information for this project can be found on the project page.

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pools associated with this project may log in and submit their votes for the standards by clicking here.

Next Steps

The voting results for the standards will be posted and announced after the ballot window closes. If approved, they will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street,
Standards Developer, or at 404-446-9702.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-004-2.1(i)a, PRC-004-4, and VAR-002-4

Final Ballot Results

Now Available

Final ballots for **PRC-004-2.1(i)a and PRC-004-4 - Protection System Misoperation Identification and Correction** and **VAR-002-4 – Generator Operation for Maintaining Network Voltage Schedules** concluded at **8 p.m. Eastern on Thursday, November 6, 2014**.

Voting statistics are listed below and the Ballot Results page provides a link to the detailed results for the ballots.

Ballot	Quorum /Approval
PRC-004-2.1(i)a	89.49% / 92.91%
PRC-004-4	87.66% / 92.15%
VAR-002-4	87.08% / 95.62%

Background information for this project can be found on the project page.

Next Steps
The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities**.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Standards Developer, Katherine Street (email), or by telephone at 404-446-9702.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-004-2.1(i)a_Final_Ballot
Ballot Period:	10/28/2014 - 11/6/2014
Ballot Type:	Final
Total # Votes:	349
Total Ballot Pool:	390
Quorum:	**89.49 % The Quorum has been reached**
Weighted Segment Vote:	92.91 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	64	0.941	4	0.059	0	21	16
2 - Segment 2	8	0.3	2	0.2	1	0.1	0	4	1
3 - Segment 3	85	1	64	0.955	3	0.045	0	15	3
4 - Segment 4	29	1	21	0.955	1	0.045	0	3	4
5 - Segment 5	92	1	68	0.944	4	0.056	0	11	9
6 - Segment 6	54	1	36	0.923	3	0.077	0	9	6
7 - Segment 7	3	0.2	1	0.1	1	0.1	0	0	1
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.2	2	0.2	0	0	0	0	0

10 - Segment 10	8	0.8	8	0.8	0	0	0	0	0
Totals	**390**	**6.8**	**269**	**6.318**	**17**	**0.482**	**0**	**63**	**41**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	

1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	COMMENT RECEIVED
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	

3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Colorado Springs Utilities	Jean Mueller	Negative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	

3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		

5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden	Negative	COMMENT RECEIVED
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	

5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Colorado Springs Utilities	Shannon Fair	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry		
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Abstain	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	

6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Ballot Results	
Ballot Name:	Project 2014-01_ PRC-004-4_Final_Ballot_October_2014
Ballot Period:	10/28/2014 - 11/6/2014
Ballot Type:	Final
Total # Votes:	341
Total Ballot Pool:	389
Quorum:	**87.66 % The Quorum has been reached**
Weighted Segment Vote:	92.15 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	104	1	63	0.926	5	0.074	0	20	16
2 - Segment 2	8	0.4	3	0.3	1	0.1	0	4	0
3 - Segment 3	85	1	59	0.922	5	0.078	0	15	6
4 - Segment 4	29	1	20	0.909	2	0.091	0	3	4
5 - Segment 5	92	1	62	0.912	6	0.088	0	11	13
6 - Segment 6	54	1	35	0.897	4	0.103	0	9	6
7 - Segment 7	3	0.2	2	0.2	0	0	0	0	1
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.2	2	0.2	0	0	0	0	0

10 - Segment 10	8	0.7	7	0.7	0	0	0	0	1
Totals	**389**	**6.8**	**256**	**6.266**	**23**	**0.534**	**0**	**62**	**48**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	

1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	COMMENT RECEIVED
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	

3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Colorado Springs Utilities	Jean Mueller	Negative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
				SUPPORTS

3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	THIRD PARTY COMMENTS
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		

5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden	Negative	COMMENT RECEIVED
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur		
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD

				PARTY COMMENTS
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Colorado Springs Utilities	Shannon Fair	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry		
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Abstain	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD

				PARTY COMMENTS
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito		
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Ballot Results	
Ballot Name:	Project 2014-01 VAR-002-4_Final_Ballot_October_2014
Ballot Period:	10/28/2014 - 11/6/2014
Ballot Type:	Final
Total # Votes:	337
Total Ballot Pool:	387
Quorum:	**87.08 % The Quorum has been reached**
Weighted Segment Vote:	95.62 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	103	1	62	0.925	5	0.075	0	18	18
2 - Segment 2	8	0.2	2	0.2	0	0	0	4	2
3 - Segment 3	85	1	63	0.955	3	0.045	0	12	7
4 - Segment 4	27	1	22	0.957	1	0.043	0	1	3
5 - Segment 5	93	1	65	0.942	4	0.058	0	11	13
6 - Segment 6	54	1	41	0.932	3	0.068	0	6	4
7 - Segment 7	3	0.2	2	0.2	0	0	0	0	1
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.2	2	0.2	0	0	0	0	0

10 - Segment 10	8	0.7	7	0.7	0	0	0	0	1
Totals	**387**	**6.6**	**269**	**6.311**	**16**	**0.289**	**0**	**52**	**50**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	

1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle		
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	COMMENT RECEIVED
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	

3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	

3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	

5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	

5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Terra-Gen Power	Jessie Nevarez	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein	Affirmative	
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Basin Electric Power Cooperative	Stephen Farnsworth	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Abstain	

6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

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Draft White Paper

Proposed Revisions to the Applicability of NERC Reliability Standards NERC Standards Applicability to Dispersed Generation Resources

Project 2014-01 Standards Applicability for Dispersed Generation Resources Standard Drafting Team

December 11, 2014

Table of Contents

1 Executive Summary

The purpose of this White Paper is to provide background and technical rationale for proposed revisions to the applicability of several North American Electric Reliability Corporation (NERC) Reliability Standards, and in some cases the standard requirements. The goal of the NERC Project 2014-01 Standards Applicability for Dispersed Generation Resources[1] standard drafting team (SDT) is to ensure that the Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System (BPS), as the characteristics of operating dispersed power producing resources can be unique. In light of the revised Bulk Electric System (BES) definition approved by the Federal Energy Regulatory Authority (FERC) in 2014[2], the intent of this effort is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources where the status quo does not create a reliability gap.

The SDT reviewed all standards that apply to GOs and GOPs[3] and determined how each standard requirement should be appropriately applied to dispersed power producing resources, categorized as follows:

- The existing standard language was appropriate when applied to dispersed power producing resources and does not need to be addressed;
- The existing standard language was appropriate when applied to dispersed power producing resources but additional NERC guidance documentation is needed to clarify how to implement the requirements for dispersed power producing resources; and
- The existing standard language needs to be modified in order to account for the unique characteristics of dispersed power producing resources. This could be accomplished through the Applicability Section of the standard in most cases or, if required, through narrowly-tailored changes to the individual requirements.

From this review, the SDT determined that three (3) Reliability Standards required immediate attention to clarify the applicability of the Reliability Standards to dispersed power producing resources for the benefit of industry stakeholders. These standards are:

- PRC-004 (relevant versions)[4];
- PRC-005 (relevant versions)[5]; and
- VAR-002 (relevant versions).

The SDT recognized that many other standards[6] required further review to determine the necessity and the type of clarification or guidance for the applicability to dispersed power producing resources. This

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[1] Although the BES definition uses the term "dispersed power producing resources," the SAR and the SDT also use the term "dispersed generation resources." For the purposes of this paper, these terms are interchangeable.
[2] Glossary of Terms Used in NERC Reliability Standards, updated March 12, 2014.
[3] See Appendix A.
[4] Reliability Standard PRC-004 was revised as part of Project 2010-05.1 Protection Systems: Misoperations.
[5] Reliability Standard PRC-005 was revised as part of Project 2007-17.3 – Protection System Maintenance and Testing – Phase 3.
[6] See Appendix B.

necessity is based on how each standard requirement, as written, would apply to dispersed power producing resources and the individual generating units at these facilities, considering the now currently-enforced BES definition. The proposed resolutions target the applicability of the standard or target specific individual requirements. There are additional methods to ensure consistent applicability throughout the Regions, including having guidance issued by NERC through Reliability Standard Audit Worksheet (RSAW) language revisions. These tools, among others, have been be considered and employed by the SDT throughout the drafting effort.

The White Paper includes: 1) description of the history of standards applicability to dispersed power producing resources; 2) identification of circumstances and practices that are unique to dispersed power producing resources; and 3) determination of the priority to address standards, supported by corresponding technical justification.

It is the intent of the SDT to modify this document over the course of this project to document the SDT's rationale and technical justification for each standard until the work of the SDT is complete. The SDT considers the sections of the White Paper that address the high-priority standards to be in final draft form. The SDT may provide further revisions to the remainder of the White Paper.

2 Purpose

The purpose of this White Paper is to provide background and technical rationale for proposed revisions to the applicability of several Reliability Standards[7] or requirements that apply to GOs and/or GOPs. The goal of the proposed applicability changes is to provide the GOs and GOPs of dispersed generation resources with clarity regarding their responsibility for requirements that impact the reliability of the BPS, as the characteristics of operating dispersed generation can be unique. The SDT seeks to provide clarity through the method most appropriate for each standard, such as by: (1) revising applicability language in the standard; (2) revising language in the requirements to address changes to applicability; (3) recommending changes to the RSAW associated with the standard; or (4) recommending a reliability guideline or reference document.

This document describes the design, operational characteristics, and unique features of dispersed power producing resources. The recommendations identified in this document consider the Purpose and Time Horizon of the standards and requirements, as well as the avoidance of applying requirements in a manner that has no significant effect on reliability.[8] This document provides justification of, and proposes revisions to, the applicability of the Reliability Standards and requirements, both existing and in development, and should be considered guidance for future standard development efforts. However, please note that the recommendations provided in this paper are subject to further review and revision.

Note that while this White Paper may provide examples of dispersed power producing resources, the concepts presented are not specific to any one technology. The SDT in general has referenced the BES Reference Document, which also refers to "dispersed power producing resources." Although the BES definition uses the term "dispersed power producing resources," the Standard Authorization Request (SAR) and the SDT also use the term "dispersed generation resources." For the purposes of this paper, these terms are interchangeable.

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[7] Note that "Reliability Standard" is defined in the NERC Glossary as "approved by FERC," but that the SDT reviewed approved standards, as well as revisions to standards proposed in other projects.

[8] *North American Electric Reliability Corporation*, 138 FERC ¶ 61,193 at P 81 (2012).

3 Background

Industry stakeholders submitted a SAR to the NERC Standards Committee, requesting that the applicability of Reliability Standards or the requirements of Reliability Standards be revised to ensure that the Reliability Standards are not imposing requirements on dispersed generation resource components that are unnecessary or counterproductive to the reliability of the BPS. The SDT's focus has been to ensure that Reliability Standards are applied to dispersed power producing resources to support an effective defense-in-depth strategy and an adequate level of reliability for the interconnected BPS.

For purposes of this effort, dispersed power producing resources are those individual 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. This request is related to the approved definition of the BES from Project 2010-17,[9] which resulted in the inclusion of distinct components of dispersed generation resources.

3.1 BES Definition

The BES definition[10] includes the following inclusion criterion addressing dispersed generation resources:

> *I4. 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. Thus, the facilities designated as BES are:*
>
> > *a) The individual resources, and*
> > *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.*

The *BES Definition Reference Document*[11] includes a description of what constitutes dispersed generation resource:

> *"Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to: solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells."*

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[9] http://www.nerc.com/pa/Stand/Pages/Project2010-17_BES.aspx
[10] Glossary of Terms Used in NERC Reliability Standards, updated March 12, 2014. http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
[11] Bulk Electric System Definition Reference Document, Version 2, April 2014. http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_reference_document_20140325_final_clean.pdf.

3.2 Dispersed Power Producing Resources

Dispersed power producing resources are often considered to be variable energy resources such as wind and solar. This description is not explicitly stated in the BES definition; however, NERC and FERC characterize variable generation in this manner regarding the purpose of Inclusion I4 of the definition.[12].Therefore, the SDT is considering the reliability impacts of variable generation that depends on a primary fuel source which varies over time and cannot be stored.[13] Reliably integrating high levels of variable resources – wind, solar, ocean, and some forms of hydro – into the BPS require significant changes to traditional methods used for system planning and operation.[14] While these resources provide challenges to system operation, these resources are instrumental in meeting government-established renewable portfolio standards and requirements that are based on vital public interests.[15]

3.2.1 Design Characteristics

For dispersed power producing resources to be economically viable, it is necessary for the equipment to be geographically dispersed. The generating capacity of individual generating modules can be as small as a few hundred watts to as large as several megawatts. Factors leading to this dispersion requirement include:

- Practical maximum size for wind generators to be transported and installed at a height above ground to optimally utilize the available wind resource;
- Spacing of wind generators geographically to avoid interference between units;
- Solar panel conversion efficiency and solar resource concentration to obtain usable output; and
- Cost-effective transformation and transmission of electricity.

The utilization of small generating units results in a large number of units (e.g., several hundred wind generators or several million solar panels) installed collectively as a single facility that is connected to the Transmission system.

Dispersed power producing resources interconnected to the transmission system typically have a control system at the group level that controls voltage and power output of the Facility. The control system is capable of recognizing the capability of each individual unit or inverter to appropriately distribute the contribution required of the Facility across the available units or inverters. The variable generation control system must also recognize and account for the variation of uncontrollable factors such as wind speed and solar irradiance levels. Thus, for some standards discussed in this paper it is appropriate to apply requirements at the plant level rather than the individual generating unit.

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[12] NERC December 13, 2013 filing, page 15 (FERC Docket No. RD14-2); NERC December 13, 2013 filing, page 17 (FERC Docket No. RD14-2); NERC January 25, 2012 filing, page 18 (FERC Docket No. RD14-2), FERC Order Approving Revised Definition, Docket No. RD14-2-000, Issued March 20, 2014.

[13] "*Electricity Markets and Variable Generation Integration,*" WECC, January 6, 2011.

[14] "*Accommodating High Levels of Variable Generation,*" NERC, April, 2009. http://www.nerc.com/files/ivgtf_report_041609.pdf

[15] *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 335, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

3.2.2 Operational Characteristics

Dispersed power producing resources often rely on a variable energy source (wind, for example) that is not able to be stored. Because of this, a Facility operator cannot provide a precise forecast of the expected output to a Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC); however, short-term forecasting capability is improving and thus reducing uncertainty.[16] The forecasting and variable operating conditions are well understood by BAs, TOPs, and RCs as evidenced by the successful operation of these generating resources over the years. Dispersed generation resources by their nature result in each individual generating unit potentially experiencing varied power system parameters (e.g. voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities design.

Many older dispersed power producing resources are limited in their ability to provide essential reliability services. However, due to technological improvements, newer dispersed generation resources are capable of providing system support for voltage and frequency. For efficiency, the facilities are designed to provide the system requirements at the point of interconnection to the transmission system.

3.2.3 Reliability Impact

A dispersed power producing resource is typically made up of many individual generating units. In most cases, the individual generating units are similar in design and from one manufacturer. The aggregated capability of the Facility may in some cases contribute significantly to the reliability of the BPS. As such, there can be reliability benefits from ensuring the equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in certain applicable NERC standards. When evaluated individually, however, the individual generating units often do not provide a significant impact to BPS reliability, as the unavailability or failure of any one individual generating resource may have a negligible impact on the aggregated capability of the Facility. The SDT acknowledges that FERC addressed the question of whether individual resources should be included in the BES definition in Order Nos. 773 and 773-A and concluded that individual wind turbine generators should be included as part of the BES. The SDT is not challenging this conclusion, but rather is addressing the applicability of standards on a requirement-by-requirement basis as necessary to account for the unique characteristics of dispersed generation. Thus, the applicability of requirements to individual generating units may be unnecessary except in cases where a common mode issue exists that could lead to a loss of a significant number of units or the entire Facility in response to a transmission system event.

3.3 Drafting Team Efforts

The SDT approached this project in multiple phases. First, after a thorough discussion of the new definition of the BES, the SDT reviewed each standard, as shown in Appendix A, at a high level to recommend changes that would promote consistent applicability for dispersed power producing resources through the entire set of Reliability Standards. This review provided the type of changes proposed, the justification for the changes, and the priority of the changes. The SDT documented its review in this

[16] "*Electricity Markets and Variable Generation Integration*," WECC, January 6, 2011. https://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/WECC%20Whitepaper%20-%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf

White Paper, which will continue to be updated throughout the SDT efforts. The second phase, currently in progress, includes revising standards where necessary and supporting the balloting and commenting process.

3.3.1 Scope of Standards Reviewed

Initially, the focus of the standards review was on standards and requirements applicable to GOs and GOPs. However, during discussions, a question was raised to the SDT whether consideration is necessary for other requirements that affect the interaction of a Balancing Authority (BA), Transmission Operator (TOP), or Reliability Coordinator (RC) with individual BES Elements. For example, a requirement that states "an RC shall monitor BES Elements" may unintentionally affect the RC operator due to the revised BES definition. As such, the SDT took a high-level look at all standards adopted by the NERC Board of Trustees (Board) or approved by FERC to ensure this issue was not significant.

All standards that were reviewed are listed in Appendix A along with the status of the standards as of December 11, 2014. The fields in Appendix A include the following:

- List of standards (grouped by approval status);
- Approval status of the standards which include
    - Subject to Enforcement
    - Subject to Future Enforcement
    - Filed and Pending Regulatory Approval
    - Pending Regulatory Filing
    - Designated for Retirement (2 standards – MOD-024-1 and MOD-025-1 – officially listed as Filed and Pending Regulatory Approval but will be superseded by MOD-025-2)
    - In concurrent active development; and
- Indication of change or additional review necessary.

The SDT also reviewed, at a high-level, any approved regional standards. In cases where a change is recommended to a regional standard, the SDT will notify the affected Region. In addition, the SDT is prepared to provide recommendations to other active NERC standard development efforts, where appropriate.

Status	Number of Standards	Number of Standards to be Addressed (Standard, RSAW, Guidance or Further Review)
NERC Standards	**166**	**27**
Subject to Enforcement	101	12
Subject to Future Enforcement	20	5
Pending Regulatory Approval	28	4
Pending Regulatory Filing	7	0
Designated for Retirement	2	0
Proposed for Remand	8	6
Region-specific Standards (*Out of Scope)	**17**	**4**
Subject to Enforcement	15	3
Subject to Future Enforcement	2	1
Pending Regulatory Approval	0	0
Grand Total	**183**	**31**

3.3.2 Reliability Objectives

The SDT used the following Reliability Objectives to review the standards:

- Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards;
- The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand;
- Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably;
- Plans for Emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented;
- Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems;
- Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions;
- The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis; and
- Bulk power systems shall be protected from malicious physical or cyber attacks.

3.3.3 Prioritization Methodology

The SDT established a prioritization to review and modify applicability changes recommended to NERC standards and requirements. The SDT evaluated each requirement to identify the appropriate applicability to support reliability of the BPS. In general, any standard or requirement the SDT determined required modification was assigned a high, medium, or low priority. The standards and requirements priorities were established as follows:

- High priority was assigned so that standard or requirement changes would be made quickly enough to avoid an entity having to expend inordinate resources prematurely to comply with a standard or requirement that, after appropriate modification, would not be applicable to that entity;
- Medium priority was assigned if significant effort and resources with no appreciable reliability benefit would be required by an entity to be compliant; and
- Low priority was assigned to other changes that may need to be made to further ensure requirements add to reliability, but are not perceived as a significant compliance burden.

The prioritization of each recommendation is identified in Appendix B.

- List of standards (grouped by priority);
- Approval status of the standards (same designations as used in Appendix A);
- Recommendation of changing the Applicability Section of the standard or by changing the applicability for specific requirements; and
- Recommendation of which applicability options should apply.

4 Technical Discussion

This section provides a review of each group of standards, focusing on the impact of the BES definition on reliability and compliance efforts. This discussion proposes a resolution for each standard, whether it is a change in the Applicability Section or in a specific requirement, clarification in a guidance document, or no action needed.

4.1 BAL

The group of BAL standards focuses primarily on ensuring the Balancing Authority (BA) has the awareness, ability, and authority to maintain the frequency and operating conditions within its BA Area. Only two standards in this group affect GO and/or GOP, and no BAL standard reviewed affected the interaction of a host BA, TOP, or RC with individual BES Elements.

4.1.1 BAL-005 — Automatic Generation Control

The purpose of this standard, as it applies to GOPs, is to ensure that all facilities electrically synchronized to the Interconnection are included within the metered boundary of a BA Area so that balancing of resources and demand can be achieved. Ensuring the Facility as a whole is within a BA Area ensures the individual units are included. *Therefore, the applicability of the BAL-005 standard does not need to be changed for dispersed power producing resources.*

4.1.2 BAL-001-TRE-1 — Primary Frequency Response in the ERCOT Region

The purpose of BAL-001-TRE-1 standard is to maintain Interconnection steady-state frequency within defined limits. This standard should be modified to clarify the applicability for dispersed power producing resources to the total plant level to ensure coordinated performance. However, this is a regional standard and not part of the SDT scope. *The SDT will communicate this recommendation to the relevant Region.*

4.2 COM

The COM standards focus on communication between the RC, BAs, TOPs, and GOPs. The only requirements in any of the current or future enforceable standards that apply to the GOP are clearly intended to apply to the individual GOP registered functional entity (i.e., requires communication between GOPs, TOPs, BAs, and RCs), not the constituent Elements it operates. Consequently, there is no need to differentiate the GOPs obligation for dispersed power producing resources from any other resources. *Therefore, the applicability of the COM-001-2, COM-002-2a, and COM-002-4 standards that were reviewed do not need to be changed for dispersed power producing resources.*

4.3 EOP

The EOP standards focus on emergency operations and reporting. The standards that apply to GO and/or GOP entities are EOP-004 and EOP-005. No EOP standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

4.3.1 EOP-004 — Event Reporting

The purpose of this standard is to improve the reliability of the BES by requiring the reporting of events by Responsible Entities. The requirements of this standard that apply to the GO and GOP appear to apply to the individual GO and GOP registered functional entity, not the constituent elements. *The SDT has considered whether there is a need to differentiate dispersed power producing resources from any other GO and/or GOP resource and determined that no changes are required to the standard.*

4.3.2 EOP-005 — System Restoration from Blackstart Resources

EOP-005 ensures plans are in place to restore the grid from a de-energized state. The requirements that apply to a GOP are primarily for individual generation facilities designated as Blackstart Resources, with one requirement to participate in restoration exercises or simulations as requested by the RC. The inclusion of Blackstart Resources is already identified in the BES definition through Inclusion I3. The expectation is that all registered GOPs will participate in restoration exercises as requested by its RC. *Therefore, the applicability of EOP-005 does not need to be changed for dispersed power producing resources.*

4.4 FAC

The FAC standards focus on establishing ratings and limits of the Facility and interconnection requirements to the BES. Several standards apply to GOs and/or GOPs. No FAC standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

4.4.1 FAC-001 — Facility Connection Requirements

Requirements R2 and R3 of this standard apply to any GO that has an external party applying for interconnection to the GO's existing Facility in order to connect to the transmission system. This scenario is uncommon and there is no precedent for applicability of this standard to dispersed *power producing* resources known to the SDT. Current practice primarily includes the GO stating that they will comply with the standard if this scenario is ever realized. This standard allows the GO to specify the conditions that must be met for the interconnection of the third-party, thus providing inherent flexibility to tailor the requirements specifically for the unique needs of the Facility. *Therefore, the applicability of FAC-001 does not need to be changed for dispersed power producing resources.*

4.4.2 FAC-002 — Coordination of Plans for New Facilities

The purpose of FAC-002 is to ensure coordinated assessments of new facilities. The requirement applicable to GOs requires coordination and cooperation on assessments to demonstrate the impact of new facilities on the interconnected system and to demonstrate compliance with NERC standards and other applicable requirements. The methods used to demonstrate compliance are independent of the type of generation and are typically completed at the point of interconnection. *Therefore, the applicability of FAC-002 does not need to be changed for dispersed power producing resources.*

4.4.3 FAC-003 — Transmission Vegetation Management

The purpose of this standard is to ensure programs and efforts are in place to prevent vegetation-related outages. This standard applies equally to dispersed generation facilities and traditional Facilities in both applicability and current practices, as it pertains to overhead transmission lines of applicable generation interconnection Facilities. *Therefore, the applicability of FAC-003 does not need to be changed for dispersed power producing resources.*

4.4.4 FAC-008 — Facility Ratings

FAC-008 ensures Facility ratings used in the planning and operation of the BES are established and communicated. The Facility ratings requirement has historically been applicable to dispersed power producing resources and current practices associated with compliance are similar to traditional generation facilities. There is inherent flexibility in the standard requirements for the GO to determine the methodology utilized in determining the Facility ratings.

To identify the Facility rating of a dispersed power producing resource the analysis of the entire suite of Facility components is necessary to adequately identify the minimum and maximum Facility Rating and System Operating Limits, and thus there would be no differentiation between the compliance obligations between dispersed power producing resources and traditional generation. *The SDT believes the industry and Regions would benefit from additional guidance on FAC-008 in the form of changes to add a technical guidance section to the standard, or other guidance.*

4.5 INT

The INT standards provide BAs the authority to monitor power interchange between BA Areas. No INT standard is applicable to the GO or GOP, or affects the interaction of a host BA, TOP, or RC with individual BES Elements. *Therefore, the applicability of the INT standards do not need to be changed for dispersed power producing resources.*

4.6 IRO

The IRO standards provide RCs their authority. There are three IRO Standards that apply directly to GO and/or GOP entities. There are three standards that apply to the interaction of the RC with individual BES Elements. No other IRO standard reviewed affected the interaction of a host BA, TOP, or RC with GOs and/or GOPs.

4.6.1 IRO-001 — Reliability Coordination — Responsibilities and Authorities[17]

The purpose of these standards and their requirements as applicable to a GOP is to ensure RC directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements, or cannot be physically implemented. If a GOP is unable to follow a RC directive they are to inform the RC immediately of such.

Directives from RCs have been traditionally applied to the dispersed power producing resource at the aggregate Facility level when they are related to either active power or voltage, such as an output reduction or the provision of voltage support. When such directives are not specific to any one Element within the Facility, it is up to the GOP to determine the appropriate method to achieve the desired result of the directive consistent with other applicable NERC Reliability Standards. When an RC directive specifies a particular Element or Elements at the GOP's Facility, it is the expectation and requirement that the GOP will act as directed, so long as doing so does not violate safety, equipment, or regulatory or statutory requirements or cannot be physically implemented. For example, a directive could specify

[17] Note that IRO-001-3, which is adopted by the Board, was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

operation of a particular circuit breaker at a GOP Facility. *For these reasons, the applicability of IRO-001 does not need to be changed for dispersed power producing resources.*

4.6.2 IRO-005 — Reliability Coordination — Current Day Operations[18]

The purpose of this standard and its requirements as it relates to GOPs is to ensure when there is a difference in derived limits the BES is operated to the most limiting parameter. A difference in derived limits can occur on any Element and therefore any limitation of the applicability of this standard may create a reliability gap. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of IRO-005 does not need to be changed for dispersed power producing resources.*

4.6.3 IRO-010 — Reliability Coordinator Data Specification and Collection

The purpose of this standard and its requirement(s) as it relates to GOs and GOPs is to ensure data and information specified by the RC is provided. As each RC area is different in nature, up to and including the tools used to ensure the reliability of the BPS, a 'one size fits all' approach is not appropriate. This Reliability Standard allows for the RC to specify the data and information required from the GO and/or the GOP, based on what is required to support the reliability of the BPS. *Therefore, the applicability of IRO-010 does not need to be changed for dispersed power producing resources.*

4.7 MOD

The MOD group of standards ensures consistent modeling data requirements and reporting procedures. The MOD standards provide a path for Transmission Planners (TPs) and Planning Coordinators (PCs) to reach out to entities for specific modeling information, if required. The SDT believes the existing and proposed modeling standards are sufficient for modeling dispersed power producing resources. However, due to the unique nature of dispersed power producing resources and an effort to bring consistency to the models, *the SDT believes additional guidance on the MOD standards would be beneficial and will communicate its determination to the NERC Planning Committee.*

4.7.1 MOD-010 — Steady-State Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-010 does not need to be changed for dispersed generation resources.*

4.7.2 MOD-012 — Dynamics Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-012 does not need to be changed for dispersed generation resources.*

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[18] Note that applicability to GOPs has been removed in IRO-005-4, which is adopted by the Board. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

4.7.3 MOD-024-1 — Verification of Generator Gross and Net Real Power Capability

This standard was established to ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2.[19] *Therefore, the applicability of MOD-024-1 does not need to be changed for dispersed generation resources.*

4.7.4 MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability

This standard was established to ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2. *Therefore, the applicability of MOD-025-1 does not need to be changed for dispersed generation resources.*

4.7.5 MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net Real and Reactive Power capability is available for planning models used to assess BES reliability. This standard is appropriate for and includes specific provisions for dispersed generation resources to ensure changes in capabilities are reported. *Therefore, the SDT is further evaluating whether to revise the applicability of the standard to align the language with the revised BES definition.*

4.7.6 MOD-026 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAR Control Functions

This standard provides for verification of models and data for voltage control functions. This standard is appropriate for dispersed generation resources. *Originally, the DGR SDT considered clarifying the applicability of the Facilities section, however, upon further review, the DGR SDT recommends no change.*

4.7.7 MOD-027 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

This standard was established to verify that the turbine/governor and frequency control model accurately represent generator unit Real Power response to system frequency variations. This standard is appropriate for dispersed generation resources. *Originally, the DGR SDT considered clarifying the applicability of the Facilities section, however, upon further review, the DGR SDT recommends no change.*

4.7.8 MOD-032 — Data for Power System Modeling and Analysis

The MOD-032 standard was established to ensure consistent modeling data requirements and reporting procedures for the planning horizon cases. The nature of dispersed generation resources is a challenge in modeling the steady-state and dynamic electrical properties of the individual components (e.g. individual units, collector system, interconnection components, etc.).

[19] MOD-024-1 and MOD-025-1 are Board Adopted but not subject to enforcement. They are commonly followed as good utility practice.

Models for dispersed power producing resources are typically proprietary and unique for each Facility. Generic models exist for dynamic analysis that may provide sufficient accuracy in lieu of a Facility-specific model. Some sections of the MOD-032 Attachment 1 pertain to modeling individual units, which may not be feasible. Guidance should be provided to show how to best model dispersed power producing resources. Such guidance should require modeling requirements for each type of dispersed power producing resource within a Facility and aggregate model for each reasonable aggregation point. *The applicability of MOD-032 does not need to be changed for dispersed power producing resources.*

4.8 NUC

The requirements in standard NUC-001 — *Nuclear Plant Interface Coordination* individually define the applicability to Registered Entities, not to the Elements the entities own or operate. While it is unlikely any Elements that are part of a dispersed power producing resource would be subject to an agreement required by this standard, limiting the applicability of this standard could create a reliability gap and thus, there is no need to differentiate applicability to dispersed generation resources. *Therefore, the applicability of the NUC standard does not need to be changed for dispersed power producing resources.*

4.9 PER

The PER standards focus on operator personnel training. The only requirements in any of the current or future enforceable standards that apply to the GOP is requirement R6 in PER-005-2 – *Operations Personnel Training,* and it is clearly intended to apply to the individual GOP registered functional entity that controls a fleet of generating facilities, not the constituent Elements it operates. As such, there is no need to differentiate dispersed power producing resources from any other GOP resources. *Therefore, the applicability of the PER standards do not need to be changed for dispersed power producing resources.*

4.10 PRC

The PRC standards establish guidance to ensure appropriate protection is established to protect the BES.

4.10.1 PRC-001-1.1 — System Protection Coordination

Requirement R1 requires GOPs to be familiar with the purpose and limitations of Protection System schemes applied in their area. The recently approved changes to the BES definition extend the applicability of this requirement. Often this familiarity is provided to GOP personnel through training on the basic concepts of relay protection and how it is utilized. The basic relaying concepts utilized in protection on the aggregating equipment at a dispersed generation site typically will not vary significantly from the concepts used in Protection Systems on individual generating units.

Requirement R2 requires that GOPs report protective relay or equipment failures that reduce system reliability. Protective System failures occurring within a single individual generating unit at a dispersed power producing resource will not have any impact on overall system reliability and thus it should not be necessary for GOPs to report these failures to their TOP and host BA. Only failures of Protection Systems on aggregating equipment have the potential to impact BPS reliability and may require notification. When interpreted as stated above, no related changes should be required to the existing PRC-001-1 standard, as the BES definition changes do not have an impact on these requirements.

Requirement R3 requires GOPs to coordinate new protective systems. Coordinating new and changes to existing protective relay schemes should be applied to aggregating equipment protection only if a lack of coordination could cause unintended operation or non-operation of an interconnected entity's protection, thus potentially having an adverse impact to the BPS. Existing industry practice is to share/coordinate the protective relay settings on the point of interconnect (e.g. generator leads, radial generator tie-line, etc.) and potentially the main step-up transformer, but not operating (collection) buses, collection feeder, or individual generator protection schemes, as these Protection Systems do not directly coordinate with an interconnected utility's own Protection Systems. Relay protection functions such as under and overfrequency and under and overvoltage changes are independent of the interconnected utility's protective relay settings and the setting criteria are defined in PRC-024.

Requirement R5 requires GOPs to coordinate changes in generation, transmission, load, or operating conditions that could require changes in the Protection Systems of others. A GOP of a dispersed generation resource should be required to notify its TOP of changes to generation, transmission, load, or operating conditions on an aggregate Facility level.

Project 2007-06 – System Protection Coordination and Project 2014-03 – Revisions to TOP and IRO Standards are presently revising various aspects of this standard or addressing certain requirements in other standards.

For these reasons, the DGR SDT coordinated with the other SDTs currently reviewing this standard and recommended revisions to Requirement R3.1 to indicate that coordination by a GOP with their TOP and host BA of new or changes to protection systems on individual generating units of dispersed power producing resources is not required.

4.10.2 PRC-001-2 — System Protection Coordination

The concerns addressed with PRC-001-1.1b are removed in PRC-001-2, which is adopted by the Board. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-03 – Revisions to TOP and IRO Standards. This Standard version is not in effect and was withdrawn as the proposed versions of the TOP and IRO Reliability Standards included in Project 2014-3 effectively replace PRC-001-2 and other TOP standards. *For this reason, no changes are required.*

4.10.3 PRC-002-NPCC-01— Disturbance Monitoring
PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting

Requirements related to installation of Fault/Disturbance monitoring and/or sequence of events (SOE) recording capabilities on generating units and substation equipment which meet regional specific criteria may require installation of these capabilities on the aggregating equipment at a dispersed power producing resource Facility, and also requires maintenance and periodic reporting requirements to their RRO. However, these requirements have been previously applicable to the aggregating equipment at these dispersed power producing resources, and these capabilities are not required to be installed on the individual generating units. The BES definition changes have no direct impact on applicability of these standards to dispersed power producing resources. *Therefore, the applicability of these standards do not need to be changed for dispersed power producing resources.*[20]

4.10.4 PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations
PRC-004-3 — Protection System Misoperation Identification and Correction

Misoperation reporting per PRC-004 is currently a requirement applied on the aggregating equipment at applicable dispersed power producing resource sites meeting BPS criteria. The continuation of this analysis and reporting on the aggregating equipment by dispersed generation resource owners can provide value to BPS reliability and should remain in place. However, based on the experience of the SDT, there is minimal impact to BPS reliability for analyzing, reporting and developing Corrective Action Plans for each individual generating unit that trips at a dispersed power producing resource site, as the tripping of one or a small number of these units has no material impact to the BPS reliability.

Additionally, reporting of Misoperations on each individual generating unit may result in substantial and unnecessary burdens on both the dispersed generation resource owner and the Regional Entities that review and track the resulting reports and Corrective Action Plan implementations. The SDT recognizes that many turbine technologies do not have the design capability of providing sufficient data for an entity to evaluate whether a Misoperation has occurred. Furthermore, dispersed power producing resources by their nature result in each individual generating unit potentially experiencing varied power system parameters (e.g., voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities design. This limits the ability to determine whether an individual unit correctly responded to a system disturbance.

However, the SDT maintains that 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 large number of the individual generation resources (aggregate nameplate rating of greater than 75 MVA) incorrectly operated or failed to operate as designed during a system event. As such, if a trip aggregating to greater than 75 MVA occurs in response to a system disturbance, the SDT proposed requiring analysis and reporting of Misoperations of individual generating units for which the root cause of the Protection System operation(s) affected an aggregate rating of greater than 75 MVA of BES Facilities. Note that the SDT selected the 75 MVA nameplate threshold for consistency and to prevent confusion.

The SDT was also concerned with the applicability of events where one or more individual units tripped and the root cause of the operations was identified as a setting error. In this case, the requirements of PRC-004 would be applicable for any individual units where identical settings were applied on the Protection Systems of like individual generation resources identified under Inclusion I4 of the BES definition.

The SDT concluded that it is not necessary under PRC-004 to analyze each individual Protection System Misoperation affecting individual generating units of a dispersed power producing resource. *The SDT*

[20] *See* NPCC CGS-005.

recommended changes to the applicability of this standard to require misoperation analysis on individual generating units at a dispersed power producing resource site, only for events affecting greater than 75MVA aggregate nameplate; the SDT determined that this will ensure that common mode failure scenarios and their potential impact on BPS reliability are appropriately addressed. The SDT's recommended changes passed industry ballot on November 6, 2014, and were approved by the Board on November 13, 2014, and are currently pending regulatory approval.

4.10.5 PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

Dispersed power producing resource sites typically would not be associated with a WECC Major Transfer Path or Remedial Action Scheme (RAS), and thus would not be affected by PRC-004-WECC-1. If a site were to be involved with one of these paths or schemes, it is likely that associated protection or RAS equipment would be located on the aggregating equipment rather than the individual generating units. As such, the BES definition changes may have an impact on applicability of this standard to dispersed power producing resources. This standard should be modified to clarify the applicability for dispersed generation resources; however, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.*

4.10.6 PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing

The SDT recognizes that PRC-005-1.1b will be phased out beginning in early 2015. Therefore, the SDT recommends only guidance on PRC-005-1.1b rather than suggesting language changes to the standard. *Therefore, the SDT does not recommend revising the applicability of this standard for dispersed generation resources, rather, the SDT provided recommendations for revisions to the applicable RSAW to NERC staff, which NERC has implemented after consultation with the Regions.*

4.10.7 PRC-005-2 — Protection System Maintenance
PRC-005-3 — Protection System and Automatic Reclosing Maintenance
PRC-005-4 — Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

The aggregated capability of the individual generating units may in some cases contribute to the reliability of the BPS; as such, there can be reliability benefit from ensuring certain BES equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in PRC-005. When evaluated individually, however, the generating units themselves do not have the same impact on BPS reliability as the system used to aggregate the units. The unavailability or failure of any one individual generating unit would have a negligible impact on the aggregated capability of the Facility; this would be irrespective to whether the dispersed generation resource became unavailable due to occurrence of a legitimate fault condition or due to a failure of a control system, protective element, dc supply, etc.

The protection typically utilized in these generating units includes elements which would automatically remove the individual unit from service for certain internal or external conditions, including an internal fault in the unit. These units typically are designed to provide generation output at low voltage levels, (i.e., less than 1000 V). Should these protection elements fail to remove the generating unit for this scenario, the impacts would be limited to the loss the individual generating unit and potentially the next device upstream in the collection system of the dispersed power producing resource. However, this would still only result in the loss of a portion of the aggregated capability of the Facility, which would be equally likely to occur due to a scenario in which a fault occurs on the collection system.

Internal faults on the low voltage system of these generating units would not be discernible on the interconnected transmission systems, as this is similar to a fault occurring on a typical utility distribution system fed from a substation designed to serve customer load. It is important to note that the collection system equipment (e.g., breakers, relays, etc.) used to aggregate the individual units may be relied upon to clear the fault condition in both of the above scenarios, which further justifies ensuring portions of the BES collection equipment is maintained appropriately.

4.10.8 For this reason, activities such as Protection System maintenance on each individual generating unit at a dispersed generation Facility would not provide any additional reliability benefits to the BPS, but Protection System maintenance on facilities where generation aggregates to 75 MVA or more would. The SDT proposes that the scope of PRC-005 be limited to include only the protection systems that operate at a point of aggregation above 75 MVA nameplate rating. If the aggregation point occurs at a component in the collection system, then the protection systems associated with this component would be in scope. *The SDT has recommended changes to the Applicability Section (Facilities) of PRC-005-2, -3, and -4 to indicate that maintenance activities should only apply on the aggregating equipment at or above the point where the aggregation exceeds 75 MVA. The SDT's recommended applicability changes to PRC-005-2 and PRC-005-3 were approved by the Board on November 13, 2014. The SDT's recommended applicability changes to PRC-005-4 were posted for an initial ballot period that ends on January 22, 2014.*PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding

PRC-006-SERC -1 — Automatic Underfrequency Load Shedding Requirements

The regional specific PRC-006 standards deviate from the PRC-006-1 standard in that they have specific requirements for GOs. In particular, the NPCC version requires that GOs set their underfrequency tripping to meet certain criteria to ensure reliability of the BPS. Typically a dispersed generation resource site may have underfrequency protection on both the aggregating equipment (i.e., collection buses or feeders) as well as the individual generating units. Were this standard only to apply to aggregating equipment, the net impact to the BPS should a system disturbance occur may still result in a loss of significant generating capacity should each of the individual generating units trip for the event. Therefore it may be appropriate to include the individual generating units at a dispersed generation resource site as subject to this standard. The standard could be interpreted this way as written, but further clarification in the standard language may be considered. While this standard may need to be modified to clarify the applicability for dispersed generation resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.*

The SERC version of PRC-006 requires GOs to provide, upon request, certain under and overfrequency related set points and other related capabilities of the site relative to system disturbances. It may be appropriate to include the capabilities of the individual generating units at a dispersed generation resource site when providing this information; however, it may be sufficient to provide only the capabilities of a single sample unit within a site as these units are typically set identically. This would be in addition to any related capabilities or limitations of the aggregating equipment as well. This may be accomplished by providing clarifications in the requirements sections. While this standard may need to be modified to clarify the applicability for dispersed power producing resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.*

4.10.9 PRC-015 — Special Protection System Data and Documentation
PRC-016 — Special Protection System Misoperations
PRC-017 — Special Protection System Maintenance and Testing

Relatively few dispersed power producing resources own or operate Special Protection Systems (SPSs); however, they do exist and therefore need to be evaluated for applicability based on the revised BES definition. The vast majority of these SPSs involve the aggregating equipment (transformers, collection breakers, etc.) and not the individual generating units. The SPSs are installed to protect the reliability of the BPS, and as such the aggregated response of the site (e.g., reduction in output, complete disconnection from the BES, etc.) is critical, not the response of individual generating units. *Therefore, the applicability of these standards does not need to be changed for dispersed power producing resources.*

4.10.10 PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Dispersed power producing resources typically utilize a site level voltage control scheme that directs the individual generating units to adjust their output to meet the voltage requirements at an aggregate Facility level. In these cases the individual generating units will simply no longer respond once they are "maxed out" in providing voltage or reactive changes, but also need to be properly coordinated with protection trip settings on the aggregating equipment to mitigate risk of tripping in this scenario. For those facilities that solely regulate voltage at the individual unit, these facilities also need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. The applicability in PRC-019-1 (section 4.2.3) includes a "Generating plant/Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating)." *Therefore, the DGR SDT revised the Facilities section of the standard to clarify that facilities which solely regulate voltage at the individual generating unit are subject to this standard's requirements. The SDT's recommended applicability changes to PRC-019-1 were posted for an initial comment and ballot period scheduled to close December 22, 2014.*

4.10.11 PRC-023— Transmission Relay Loadability

Dispersed power producing resources in some cases contain facilities and Protection Systems that meet the criteria described in the Applicability Section (e.g., load responsive phase Protection System on transmission lines operated at 200 kV or above); however, in the majority of cases these lines are radially connected to the remainder of the BES and are excluded from the standard requirements of PRC-023-3. While certain entities with dispersed power producing resources are required to meet the requirements of PRC-023 on components of their aggregating equipment (e.g., main step-up transformers, interconnecting transmission lines) the standard is not applicable to the individual generating units, as the individual generating units are addressed in PRC-025. The BES definition changes have no direct impact on the applicability of this standard to dispersed power producing resources. *Therefore, the applicability of this standard does not need to be changed for dispersed power producing resources.*

4.10.12 PRC-024— Generator Frequency and Voltage Protective Relay Settings

If the individual generating units at a dispersed power producing resource were excluded from this requirement, it is possible large portions or perhaps the entire output of a dispersed power producing resource site may be lost during certain system disturbances, negatively impacting BES reliability. The SDT has determined it is appropriate to require that Protection System settings applied on both the individual generating units and aggregating equipment (including any Protection Systems applied on non-BES portions of the aggregating equipment), are set within the "no-trip zone" referenced in the requirements to maintain reliability of the BES. However, for the purpose of compliance evidence, the SDT believes it should be sufficient for an entity to provide evidence for a single sample generating unit within a site rather than providing documentation for each individual unit, providing the entity used that methodology to set its protection systems for all the units, rather than providing documentation for each individual unit. This would be in addition to any Protection System settings evidence for the aggregating equipment. *The SDT therefore recommended changes to the standard requirements to ensure these requirements are applied to the individual power producing resources as well as all equipment, potentially including non-BES equipment, from the individual power producing resource up to the point of interconnection and communicated compliance evidence requirement considerations to NERC staff for RSAW development. The SDT's recommended applicability changes to PRC-024 were posted for an initial comment and ballot period scheduled to close December 22, 2014.*

4.10.13 PRC-025— Generator Relay Loadability

The Protection System utilized on individual generating units at a dispersed power producing Facility may include load-responsive protective relays and thus would be subject to the settings requirements listed in this standard. Were this standard only to apply to aggregating equipment, the net impact to the BPS should a system disturbance occur, may be a loss of significant generating capacity should each of the individual generating units trip for the event. The SDT has determined it is appropriate to require that Protection System settings applied on both the individual generating units at a dispersed power producing resource site as applicable to this standard. However, for the purpose of compliance evidence, the SDT believes it should be sufficient for an entity to provide evidence for a single sample generating unit within a site rather than providing documentation for each individual unit, providing the entity used that methodology to set its protection systems for all the units, rather than providing documentation for each individual unit. This would be in addition to any Protection System settings evidence for the aggregating equipment. As such the SDT recommends the RSAW be modified as stated above. *The SDT recommended no changes to the standard; however, the DGR SDT communicated compliance evidence requirement considerations to NERC staff for RSAW development.*

4.11 TOP

The TOP standards provide TOPs their authority. There are four TOP standards that apply directly to GO and GOP entities. The TOP standards as they relate to GOs/GOPs ensure RCs and TOPs can issue directives to the GOP, and the GOP follows such directives. They also ensure GOPs render all available emergency assistance as requested. Finally, they require GO/GOPs to coordinate their operations and outages and provide data and information to the BA and TOP. No TOP standard refers to the interaction of a host BA, TOP, or RC with individual BES Elements.

4.11.1 TOP-001-1a — Reliability Responsibilities and Authorities

This standard as it applies to GOPs is reviewed at the requirement level, with only one change recommended.

4.11.1.1 Requirement R3

The purpose of requirement R3 as it relates to GOPs is to ensure the RC and TOP reliability directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow a RC or TOP reliability directive they are to inform the RC or TOP immediately of such. The requirement is applicable to the registered functional entity, not the constituent Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed power producing resources from any other GOP resources, and no change to this requirement is needed.*

4.11.1.2 Requirement R6

The purpose of requirement R6 as it relates to GOPs is to ensure all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements. The requirement is applicable to the registered functional entity, not the constituent Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed power producing resources from any other GOP resources, and no change to this requirement is needed.*

4.11.1.3 Requirement R7

The purpose of requirement R7 as it relates to GOPs is to ensure BES facilities are not removed from service without proper notification and coordination with the TOP and, when time does not permit such prior notification and coordination, notification and coordination shall occur as soon as reasonably possible. This is required to avoid burdens on neighboring systems. It should be noted that the purpose of this standard is to keep the TOP informed of all generating Facility capabilities in case of an emergency. It is assumed that required notification and coordination from the GOP to the TOP would be done in real-time and through verbal communication media. The concern here is how to apply this to a dispersed power producing resource Facility. The SDT recommends that the GOP report at the aggregate Facility level to the TOP any generator outage above 20 MVA for dispersed power producing resource facilities. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition, which addresses only generating units greater than 20 MVA.
- TOP-002-2.1b Requirement R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the Facility (e.g., 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.

Dispersed power producing resource outages should be reported as X MW out of Y MW are available. *Therefore, the SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for generator outages greater than 20 MVA.*

4.11.2 TOP-001-3— Transmission Operations[21]

The purpose of this standard as it relates to GOPs is to ensure TOP directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow a TOP directive they are to inform the TOP immediately of such. It directs the TOP to issue directives and as such the TOP may provide special requirements for dispersed power producing resources for its unique capabilities. *The SDT recommends that Project 2014-3 provide direction for a dispersed power producing resource to be only reported at the aggregate facility level. If TOP-001-1a R7 is reintroduced, then the recommendation provided above should be included in their efforts.*

4.11.3 TOP-002-2.1b — Normal Operations Planning[22]

This TOP standard has five requirements applied to GOPs. Several modifications are recommended below, and the SDT recommends that the most effective and efficient way to accomplish this is through modification of the Applicability Section of this standard.

4.11.3.1 Requirement R3

The purpose of requirement R3 as it relates to GOPs is to ensure a GOP's current day, next-day and seasonal operations are coordinated with its host BAs and TSP. This requirement relates to planned operations at a generator and does not include unplanned operations such as forced or emergency operations. The SDT recommends that this requirement be applied at the aggregate Facility level for dispersed power producing resources. For example, forecasting available MW at the aggregated Facility level is currently one method used. The SDT does not see any reliability gap in that would prompt this team to apply R3 to any point less than the dispersed power resource aggregated Facility level.
The SDT has not found or been made aware of a reliability gap that would prompt this team to apply R3 to any point less than the dispersed power resource aggregated Facility level and recommends such modification to the applicability of this requirement.

4.11.3.2 Requirement R13

The purpose of requirement R13 as it relates to GOPs is to ensure Real Power and Reactive Power capabilities are verified as requested by the BA and TOP. The SDT believes a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT is recommending that this requirement be applied at the aggregate Facility level for dispersed power producing resources for the following reasons:

- Due to the nature, amount of individual generators at a dispersed power producing resource, internal Real Power losses, and natural inductance and capacitance of dispersed power resource

[21] Note that TOP-001-2 was adopted by the Board and remanded by FERC. TOP-001-2 is currently under revision as part of Project 2014-03 – Revisions to TOP and IRO Standards, and was posted for additional ballot period that is scheduled to close January 7, 2015 as TOP-001-3.
[22] The GOP applicability is removed in TOP-002-3, which was adopted by the Board. However, TOP-002-3 was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

system connected in series, verification of real and reactive capabilities should be conducted at the dispersed power producing resource aggregate Facility level. Performing verification in this manner will provide an actual net real and reactive capability, which would be seen by both the BA and TOP. In addition, performing verification in this manner is also consistent with operating agreements such as an interconnection agreement, which the dispersed power resource has with the TOP and BA.

- MOD-025-2 also provides that verification for any generator <20MVA may be completed on an individual unit basis or as a "group." Reporting capability at the aggregated Facility level is consistent with the MOD-025-2 provision for group verification.

The SDT recommends a modification to the applicability of this requirement at the aggregated Facility level for dispersed power producing resources.

4.11.3.3 Requirement R14

The purpose of requirement R14 as it relates to GOPs is to ensure BAs and TOPs are notified of changes in real output capabilities without any intentional time delay. It should be noted that the purpose of this requirement is to address unplanned changes in real output capabilities. It is assumed the required notification and coordination from the GOP to the BA and TOP would be done in real-time and through verbal communication media. The concern here is how to apply this to dispersed power producing resources. The SDT recommends that the GOP notify at the aggregate Facility level to the TOP any unplanned changes in real output capabilities above 20 MVA. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition which includes generating units greater than 20MVA; and
- TOP-002-2.1b R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the Facility (e.g. 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.

Dispersed generation resources changes in real output capabilities should be reported as X MW out of Y MW are available. *The SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for unplanned outages greater than 20 MVA.*

4.11.3.4 Requirement R15

The purpose of requirement R15 as it relates to GOPs is to ensure BAs and TOPs are provided a forecast (e.g., seven day) of expected Real Power. The SDT believes this requirement as requested by the BA or TOP is being applied at the aggregate Facility level for dispersed power producing resources.

Based on the SDT's experience, expected Real Power forecasts (e.g. 5 or 7 forecast) for a dispersed power producing resource has been traditionally coordinated with the BA and TOP at the aggregate Facility level for dispersed power producing resources. *Therefore, the SDT recommends that R15 be applied at the aggregate Facility level for dispersed power resources and as such, modification to the applicability of this requirement is necessary.*

4.11.3.5 Requirement R18
The purpose of requirement R18 as it relates to a GOP is to ensure uniform line identifiers are used when referring to transmission facilities of an interconnected network. The standard applies to transmission facilities of an interconnected network, which would not apply to any Elements within the dispersed generation Facility. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

4.11.4 TOP-003-1— Planned Outage Coordination

This TOP Standard has three requirements applied to GOPs. Modification to one of these requirements is recommended.

4.11.4.1 Requirement R1
The purpose of requirement R1 as it relates to GOPs is to ensure TOPs are provided planned outage information on a daily basis for any scheduled generator outage >50MW for the next day. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

4.11.4.2 Requirement R2
The purpose of requirement R2 as it relates to GOPs is to ensure all voltage regulating equipment scheduled outages are planned and coordinated with affected BAs and TOPs. A modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT recommends that this requirement be applied at the aggregate Facility level for dispersed power producing resources.

Based on the SDT's experience, scheduled outages of voltage regulating equipment at a dispersed power producing resource has been traditionally provided to the BA and TOP at the aggregate Facility level for dispersed power producing resources. Outages of voltage regulating equipment at a dispersed power producing resource are coordinated typically as a reduction in Reactive Power capabilities, specifying whether it is inductive, capacitive or both. Additionally, automatic voltage regulators that do not necessarily provide Reactive Power, but direct the actions of equipment that do supply Reactive Power, are typically coordinated at the aggregate Facility level as they usually are the master controller for all voltage regulating equipment at the Facility. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap, which would prompt this team to apply R2 to any point less than the dispersed power producing resource aggregated Facility level and as such, determined a modification to the applicability of this requirement is necessary for dispersed power producing resources.*

4.11.4.3 Requirement R3
The purpose of requirement R3 as it relates to GOPs is to ensure scheduled outages of telemetering and control equipment and associated communication channels are planned and coordinated among BAs and TOPs. Based on the SDT technical expertise, scheduled outages of telemetering and control equipment and associated communication channels at a dispersed power producing resource have been traditionally provided to the BA and TOP at the aggregate Facility level for dispersed power producing resources. In addition, only scheduled outages of telemetering and control equipment and associated communication

channels that can affect the BA and TOP are coordinated with the BA and TOP. *Therefore, the applicability of this requirement does not need to be changed for dispersed power producing resources.*

4.11.5 TOP-006 — Monitoring System Conditions

The purpose of this standard as it relates to GOPs is to ensure BAs and TOPs know the status of all generation resources available for use as informed by the GOP. It should also be noted that the purpose of this standard is to ensure critical reliability parameters are monitored in real-time. It then can be extrapolated that the requirement, "GOP shall inform…," is done by sending dispersed power producing resource telemetry in real-time and through a digital communication medium, such as an ICCP link or RTU. The SDT feels a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT is recommending that this requirement be applied at the aggregate Facility level for dispersed power producing resources for the following reasons:

- This is consistent with Inclusion I2 of the revised BES definition, which includes generating units greater than 20MVA. If removing <20MVA would cause a burden to the BPS, then the threshold for inclusion in the BES would have been less than 20MVA;
- Routine maintenance is frequently completed on a small portion of the entire Facility (e.g. 2% of the generators are out of service on any given day) such as to not have a significant impact to the output capability of the Facility. Additionally, it is not uncommon to have individual generating units at a dispersed power producing resource to go into a failure mode due to internal factors of the equipment, such as hydraulic fluid pressure tolerances, gearbox bearing thermal tolerances, etc. As such, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS; and
- As this standard requires real-time monitoring, this is most likely completed through a digital medium such as an ICCP link or RTU. The data that a dispersed power resource provides to the BA and TOP in real-time should include the aggregate active power output of the Facility, among other telemetry points. These data specifications are usually outlined in interconnection agreements among the parties.

Based on the SDT technical expertise, BAs and TOPs are informed by the GOP of all generation resources available at the dispersed power producing resource at the aggregate Facility level. Traditionally the dispersed power producing resources are providing the BA and TOP, at minimum, the following telemetry points in real-time: aggregate Real Power, aggregate Reactive Power and main high-side circuit breaker status. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap, which would prompt this team to apply these requirement to any point less than where the dispersed power producing resource aggregates and as in such, recommends a modification to the applicability of this requirement is necessary for dispersed power producing resources.*

4.12 TPL

At the time of this paper, these standards do not affect GOs or GOPs directly. Input from GO or GOP entities is provided to transmission planning entities through the MOD standards. *Therefore, the applicability of the TPL standards does not need to be changed for dispersed power producing resources.*

4.13 VAR

The VAR standards exist to ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained. There are two VAR Standards that apply to GOs and/or GOPs. The voltage and/or reactive schedule provided by TOPs is specified to be at the point of interconnection or the point specified in the interconnection agreement.

4.13.1 VAR-001 — Voltage and Reactive Control (WECC Regional Variance)

The purpose of this standard as it relates to GOPs in WECC is to ensure a generator voltage schedule is issued that is appropriate for the type of generator(s) at a specific Facility. Additionally, it requires GOPs to have a methodology for how the voltage schedule is met taking into account the type of equipment used to maintain the voltage schedule. Based on the SDT technical expertise, voltage control and voltage schedule adherence for dispersed power producing resource occurs at the aggregate Facility level. There is no need to differentiate dispersed generation resources from any other GOP resources. *Therefore, the applicability of VAR-001 does not need to be changed for dispersed generation resources.*

4.13.2 VAR-002-2b — Generator Operation for Maintaining Network Voltage Schedules VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

The purpose of these standards as they relate to GOs and GOPs is to ensure generators operate in automatic voltage control mode as required by the TOP voltage or reactive power schedule provided to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and reliability of the Interconnection. Based on the SDT technical expertise, voltage control and voltage schedule adherence for dispersed power producing resource occurs at the aggregate Facility level and such guidance should be provided.

In addition, the voltage-controlling equipment and the methodology to ensure the Facility has an automatic and dynamic response to ensure the TOP's instructions are maintained can be very different for each Facility. It is implied in VAR-001-3 that each TOP should understand capabilities of the generation Facility and the requirements of the transmission system to ensure a mutually agreeable solution/schedule is used.

4.13.3 VAR-002-2b — Requirement R3.1
VAR-002-3 — Requirement R4

4.13.4 The purpose of these requirements is to ensure that a GOP notifies the TOP, within 30 minutes, any status and capability changes of any generator Reactive Power resource, including automatic voltage regulator, power system stabilizer or alternative voltage controlling device. Based on the experience of the SDT, status and capability changes is traditionally coordinated at the aggregate Facility level point of interconnection. *Therefore, the SDT has recommended changes to the standard to clarify the applicability of VAR-002-2b R3.1 and VAR-002-3 R4 for dispersed power producing resources. These changes were successfully balloted in VAR-002-4 on November 6, 2014, and approved by the Board on November 13, 2014.*VAR-002-2b — Requirement R4
VAR-002-3 — Requirement R5

The purpose of these requirements is to ensure that Transmission Operators and Transmission Planners have appropriate information and provide guidance to the GOP in regards to Generator Operator's transformers to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and reliability of the Interconnection. Based on the experience of the SDT dispersed power producing resources individual generator transformers have traditionally been excluded from the requirements of VAR-002-2b R4 and VAR-002-3 R5, as they are not used to improve voltage performance on the Interconnection. As such, applicability should be limited to transformers with at least one winding at a voltage of 100kV or above. *Therefore, the SDT has recommended changes to the standard to clarify the applicability of VAR-002-2b R4 and VAR-002-3 R5 for dispersed generation resources. These changes were successfully balloted in VAR-002-4 on November 6, 2014, and approved by the Board on November 13, 2014.*

4.14 CIP

4.14.1 CIP v5

The CIP standards are still under revision in Project 2014-02. The DGR SDT and the CIP SDT continue to coordinate revisions to the CIP standards, and will update this section to reflect the outcome of that effort at the appropriate time.

The CIP standards ensure physical and cyber security for BES Cyber Assets and BES Cyber Systems critical to the reliability and security of the BES. CIP-002 identifies critical assets or systems of a Facility, while CIP-003 to CIP-011 depend on the outcome of the CIP-002 assessment to determine applicability.

During the Project 2014-02 CIP Version 5 Revisions SDT first comment period, it received comments to modify CIP-003-6 in the Applicability Section. The CIP SDT made drastic modifications to the second posting of CIP-003-6 to take into accounts all of the comments received, which was posted for an additional 45-day comment and ballot period on September 3, 2014.

At its September meeting, the DGR SDT had a focused discussion with the CIP SDT surrounding the technical nature of the dispersed power producing resources and how it relates to the CIP standards. The coordinating effort resulted in discussions of the revised CIP-003-6. As for that posted revised standard, the CIP SDT took the approach of including an Attachment 1 for Responsible Entities. The Attachment 1 requires elements to be developed in Responsible Entities' cyber security plan(s) for assets containing low impact BES Cyber Systems. The elements in CIP-003-6, Attachment 1 allow flexibility for the controls to be established for each of the main four elements below. The CIP SDT encourages observers of the DGR SDT to review the Attachment 1 in detail. Here is some information regarding the attachment.

Element 1: Security Awareness

The intent of the security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. It is up to the entity as to the topics and how it schedules these topics. The Responsible Entity should be able to produce the awareness material that was delivered and the delivery method(s) (posters, emails, topics at staff meetings, etc.) that were used. The SDT does not intend that the Responsible Entity must maintain lists of recipients and track the reception of the awareness material by personnel.

Element 2: Physical Security

The Responsible Entity has flexibility in the controls used to restrict physical access to low impact BES Cyber Systems at a BES asset using one or a combination of access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may utilize perimeter controls (e.g., fences with locked gates, guards, site access policies, etc.) and/or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses. User authorization programs and lists of authorized users are not required.

Element 3: Electronic Access Controls

Where Low Impact External Routable Connectivity (LERC) or Dial-up Connectivity exists, the Responsible Entity must document and implement controls that include the LERC and Dial-up Connectivity to the BES asset such that the low impact BES Cyber Systems located at the BES asset are protected. Two glossary terms are included in order to help clarify and simplify the language in Attachment 1. The SDT's intent in creating these terms is to avoid confusion with the similar concepts and requirements (ESP, EAP, ERC, EACMS) needed for high and medium impact BES Cyber Systems by utilizing separate terms that apply only to assets containing low impact BES Cyber Systems.

Element 4: Cyber Security Incident Response

The entity should have one or more documented cyber security incident response plans that include each of the topics listed. For assets that do not have LERC, it is not the intent to increase their risk by increasing the level of connectivity in order to have real-time monitoring. The intent is if in the normal course of business suspicious activities are noted at an asset containing low impact BES Cyber Systems, there is a cyber security incident response plan that will guide the entity through responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Therefore, the DGR SDT recommends that no changes be made to proposed CIP-003-6. CIP-002-5.1 needs to remain as is because entities must go through the process for identifying and categorizing its BES Cyber Systems and their associated BES Cyber Assets. The controls put in place for proposed CIP-003-6, Attachment 1, are not burdensome, are realistic and achievable, and does not express undue compliance burden. In conclusion, the DGR SDT states that the reliability objective of these controls are adequate and the applicability of CIP-003-6 should not be modified.

The SDT states that the CIP Version 5 Revisions SDT should consider developing guidance documentation around the following areas:

- Low Impact BES Cyber Systems that must comply with a limited number of requirements, all located in CIP-003-5. The only technical requirement is R2, which will be modified during the current drafting activity to add clarity to the requirement. The SDT notes that the CIP Version 5 Revisions SDT should consider developing guidance around how this requirement relates to dispersed generation;
- Any programmable logic device that has the capability to shut down the plant within 15 minutes; and
- Remote access from third party entities into the SCADA systems that control the aggregate capacity of a Facility should be assessed to determine if there is a need of any additional cyber security policies.

The SDT intends to recommend guidance for those companies that only operate their turbines from one central location. Individual Elements lumped into a BES Cyber System should be addressed. When operations are on a turbine-by-turbine basis, the SDT believes there should not be rigid controls in place. The inability to "swim upstream" should be addressed as well. Further, the guidance intends to address when manufacturers operate or have control of the SCADA environment to conduct troubleshooting and other tasks, and ensure that proper security is in place.

NERC staff has committed to facilitate communication between the SDT and the CIP Version 5 Revisions SDT as appropriate to ensure alignment and to develop language for guidance, coordinated between the two SDTs. *Therefore, the applicability of CIP standards does not need to be changed for dispersed generation resources.*

Appendix A: List of Standards

Appendix B: List of Standards Recommended for Further Review

Draft White Paper

Proposed Revisions to the Applicability of NERC Reliability Standards NERC Standards Applicability to Dispersed Generation Resources

Project 2014-01 Standards Applicability for Dispersed Generation Resources Standard Drafting Team

~~October 5~~December 11, 2014

Table of Contents

1 Executive Summary

The purpose of this ~~white~~ White ~~paper~~ Paper is to provide background and technical rationale for proposed revisions to the applicability of several North American Electric Reliability Corporation (NERC) Reliability Standards, and in some cases the standard requirements. The goal of the NERC Project 2014-01 Standards Applicability for Dispersed ~~Power Producing~~Generation Resources[1] standard drafting team (SDT) is to ensure that the Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System (BPS), as the characteristics of operating dispersed power producing resources can be unique. In light of the revised Bulk Electric System (BES) definition approved by the Federal Energy Regulatory Authority (FERC) in 2014[2], the intent of this effort is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources where the status quo does not create a reliability gap.

The SDT reviewed all standards that apply to GOs and GOPs[3] and determined how each standard requirement should be appropriately applied to dispersed power producing resources, categorized as follows:

- The existing standard language was appropriate when applied to dispersed power producing resources and does not need to be addressed;
- The existing standard language was appropriate when applied to dispersed power producing resources but additional NERC guidance documentation is needed to clarify how to implement the requirements for dispersed power producing resources; and
- The existing standard language needs to be modified in order to account for the unique characteristics of dispersed power producing resources. This could be accomplished through the ~~applicability~~ Applicability ~~section~~ Section of the standard in most cases or, if required, through narrowly~~-~~tailored changes to the individual requirements.

From this review, the SDT determined that~~there are~~ three (3) Reliability S~~s~~tandards~~-~~ required ~~in which the SDT feels~~ immediate attention ~~is required~~ to clarify the applicability of the Reliability Standards to dispersed power producing resources for the benefit ~~provide direction~~of ~~to~~ industry stakeholders~~ as soon as feasible regarding how to appropriately direct compliance related preparations~~. These standards ~~include~~are:

- PRC-004 (relevant versions)[4];
- PRC-005 (relevant versions)[5]; and

[1] Although the BES definition uses the term "dispersed power producing resources," the SAR and the SDT also use the term "dispersed generation resources." For the purposes of this paper, these terms are interchangeable.
[2] Glossary of Terms Used in NERC Reliability Standards, updated March 12, 2014.
[3] See Appendix A.
[4] Reliability Standard PRC-004 ~~is currently being~~was revised as part of Project 2010-05.1 Protection Systems: Misoperations.
[5] Reliability Standard PRC-005 ~~is currently being~~was revised as part of Project 2007-17.3 – Protection System Maintenance and Testing – Phase 3.

- VAR-002 (relevant versions)[6].

~~However, t~~The SDT ~~has~~ recognized that many other standards[7] required further review ~~by the SDT~~ to determine the necessity and the type of clarification or guidance for the applicability to dispersed power producing resources. This necessity is based on how each standard requirement, as written, would apply to dispersed power producing resources and the individual generating units at these facilities, considering the ~~recently approved~~now currently-enforced BES definition. The proposed resolutions target the applicability of the standard ~~noted in the language of the applicability section~~ or ~~specifically~~ target specific individual requirements. There are additional methods to ensure consistent applicability throughout the Regions, including having guidance issued by NERC through Reliability Standard Audit Worksheet (RSAW) language revisions. These tools, among others, have been be considered and employed by the SDT throughout the ~~work~~ drafting effort.

The~~ technical section of this~~ White P~~p~~aper~~ includes insight from the SDT review,~~ includes:~~ing~~ 1) description of the history of standards applicability to dispersed power producing resources;~~,~~ 2) identification of ~~any unique~~ circumstances and practices that are unique to~~for~~ dispersed power producing resources~~ and current practices,~~ ; and 3)~~as well as~~ ~~the SDT's categorization and~~ determination of the priority to address standards, supported by corresponding technical justification.

~~This white paper is a living document.~~ It is the intent of the SDT to modify this document over the course of this project to document the SDT's rationale and technical justification for each standard until the work of the SDT is complete. The SDT considers the sections of the ~~w~~White ~~p~~Paper that address the high-priority standards to be in final draft form. The SDT may provide further revisions to the remainder of the ~~w~~White ~~p~~Paper.

[6] Reliability Standard VAR-002 was~~is currently being~~ revised as part of Project 2013-04 – Voltage and Reactive Control.

[7] See Appendix B.

2 Purpose

The purpose of this ~~white paper~~White Paper is to provide background and technical rationale for proposed revisions to the applicability of several Reliability Standards[8] or requirements that apply to GOs and/or GOPs. The goal of the proposed applicability changes is to ~~ensure that~~provide the GOs and GOPs of dispersed generation resources with~~have~~ clarity regarding~~as to~~ their responsibility for requirements that impact the reliability of the BPS, as the characteristics of operating dispersed generation can be unique. The SDT seeks to provide ~~is~~ clarity through the method most appropriate for each standard, such as~~will be accomplished through revised~~ by: (1) revising applicability language in the standard;~~s,~~ (2) revising language in the requirements to address changes to applicability; (3) recommending~~ed~~ changes to the RSAW associated with the standard;~~,~~ or (4) recommending~~ations for~~ a reliability guideline or reference document.

This document describes~~lays out a common understanding of~~ the design, ~~and~~ operational characteristics, and unique features of dispersed power producing ~~generation~~ resources~~, highlighting the unique features of dispersed generation resources~~. The recommendations identified in this document consider the ~~purpose~~ Purpose and ~~time~~ Time ~~horizon~~ Horizon of the standards and requirements, as well as the avoidance of applying requirements in a manner that has no significant effect on reliability.[9] This document provides justification of, and proposes revisions to, the applicability of the Reliability Standards and requirements, both existing and in development, and should be considered guidance for future standard development efforts. However, please note that the recommendations provided in this paper are subject to ~~comment and~~ further review and revision.

Note that while this ~~paper~~ White Paper may provide examples of dispersed power producing ~~generation~~ resources, the concepts presented are not specific to any one technology. The ~~Dispersed Generation Resources~~ SDT in general has referenced the BES Reference Document, which also refers to "dispersed power producing resources." Although the BES definition uses the term "dispersed power producing resources," the Standard Authorization Request (SAR) and the SDT also use the term "dispersed generation resources." For the purposes of this paper, these terms are interchangeable.

[8] Note that "Reliability Standard" is defined in the NERC Glossary as "approved by FERC," but that the ~~Dispersed Generation Resources~~ SDT reviewed approved ~~and unapproved~~ standards, as well as revisions to standards proposed in other projects.

[9] *North American Electric Reliability Corporation*, 138 FERC ¶ 61,193 at P 81 (2012).

3 Background

~~By submitting~~ Industry stakeholders submitted a SAR to the NERC Standards Committee, ~~industry stakeholders~~ requesting~~ed~~ that the applicability of Reliability Standards or the requirements of Reliability Standards be revised to ensure that the Reliability Standards are not imposing requirements on dispersed generation resource components that are unnecessary or counterproductive to the reliability of the BPS. The SDT's focus has been to ensure that Reliability Standards are applied to dispersed power producing resources to support an effective defense-in-depth strategy and an a~~A~~dequate l~~L~~evel of r~~R~~eliability for the ~~reliability of the~~ interconnected BPS.

For purposes of this effort, dispersed ~~generation~~ power producing resources are those individual 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. This request is related to the approved definition of the BES from Project 2010-17,[10] which resulted in the inclusion of distinct components of dispersed generation resources.

3.1 BES Definition

The BES definition[11] includes the following inclusion criterion addressing dispersed generation resources:

> *I4. 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. Thus, the facilities designated as BES are:*
>
> > *a) The individual resources, and*
> > *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.*

~~Upon implementation of Inclusion I4, NERC standards and requirements applicable to Generator Owners and Generator Operators will apply to owners and operators of all of the components included in the definition, notably each individual generator of a dispersed generation resource facility in those requirements, except in certain standards that explicitly identify the applicable facilities or provide specific guidance on applicability to dispersed generation resources.~~

The *BES Definition Reference Document*[12] includes a description of what constitutes dispersed generation resource:

> *"Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity*

[10] http://www.nerc.com/pa/Stand/Pages/Project2010-17_BES.aspx
[11] Glossary of Terms Used in NERC Reliability Standards, updated March 12, 2014. http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
[12] Bulk Electric System Definition Reference Document, Version 2, April 2014. http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_reference_document_20140325_final_clean.pdf.

providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to: solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells."

3.2 Dispersed Power Producing Resources

Dispersed power producing resources are often considered to be variable energy resources such as wind and solar. This description is not explicitly stated in the BES definition; however, NERC and FERC characterize variable generation in this manner regarding the purpose of Inclusion I4 of the definition.[13]. Therefore, the SDT is considering the reliability impacts of variable generation that depends on a primary fuel source which varies over time and cannot be stored.[14] Reliably integrating high levels of variable resources – wind, solar, ocean, and some forms of hydro – into the BPS require significant changes to traditional methods used for system planning and operation.[15] While these resources provide challenges to system operation, these resources are instrumental in meeting government-established renewable portfolio standards and requirements that are based on vital public interests.[16]

3.2.1 Design Characteristics

For dispersed power producing resources to be economically viable, it is necessary for the equipment to be geographically dispersed. The generating capacity of individual generating modules can be as small as a few hundred watts to as large as several megawatts. Factors leading to this dispersion requirement include:

- Practical maximum size for wind generators to be transported and installed at a height above ground to optimally utilize the available wind resource;
- Spacing of wind generators geographically to avoid interference between units;
- Solar panel conversion efficiency and solar resource concentration to obtain usable output; and
- Cost-effective transformation and transmission of electricity.

The utilization of ~~these~~ small generating units results in a large number of units (e.g., several hundred wind generators or several million solar panels) installed collectively as a single facility that is connected to the ~~transmission~~ Transmission system.

Dispersed ~~generation~~ power producing resources interconnected to the transmission system typically have a control system at the group level that controls voltage and power output of the ~~facility~~Facility. The control system is capable of recognizing the capability of each individual unit or inverter to appropriately distribute the contribution required of the ~~facility~~Facility across the available units or inverters. The

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[13] NERC December 13, 2013 filing, page 15 (FERC Docket No. RD14-2); NERC December 13, 2013 filing, page 17 (FERC Docket No. RD14-2); NERC January 25, 2012 filing, page 18 (FERC Docket No. RD14-2), FERC Order Approving Revised Definition, Docket No. RD14-2-000, Issued March 20, 2014.

[14] "*Electricity Markets and Variable Generation Integration*,"~~,~~ WECC, January 6, 2011. ~~https://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/WECC%20Whitepaper%20-%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf~~

[15] "*Accommodating High Levels of Variable Generation*,"
~~,~~ NERC, April, 2009. http://www.nerc.com/files/ivgtf_report_041609.pdf

[16] *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 335, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

variable generation control system must also recognize and account for the variation of uncontrollable factors such as wind speed and solar irradiance levels. Thus, for some standards discussed in this paper it is appropriate to apply requirements at the plant level rather than the individual generating unit.

3.2.2 Operational Characteristics

Dispersed ~~generation~~ power producing resources often rely on a variable energy source (wind, for example) that is not able to be stored. Because of this, a ~~facility~~Facility operator cannot provide a precise forecast of the expected output to a Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC); however, short-term forecasting capability is improving and thus reducing uncertainty.[17] The forecasting and variable operating conditions are well understood by BAs, TOPs, and RCs as evidenced by the successful operation of these generating resources over the years. Dispersed generation resources by their nature result in each individual generating unit potentially experiencing varied power system parameters (e.g. voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities design.

Many older dispersed ~~generation~~ power producing resources are limited in their ability to provide essential reliability services. However, due to technological improvements, newer dispersed generation resources are capable of providing system support for voltage and frequency. For efficiency, the facilities are designed to provide the system requirements at the point of interconnection to the transmission system.

3.2.3 Reliability Impact

A dispersed ~~generation~~ power producing resource is typically made up of many individual generating units. In most cases, the individual generating units are similar in design and from one manufacturer. The aggregated capability of the ~~facility~~Facility may in some cases contribute significantly to the reliability of the BPS. As such, there can be reliability benefits from ensuring the equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in certain applicable NERC standards. When evaluated individually, however, the individual generating units often do not provide a significant impact to BPS reliability, as the unavailability or failure of any one individual generating resource may have a negligible impact on the aggregated capability of the ~~facility~~Facility. The SDT acknowledges that FERC addressed the question of whether individual resources should be included in the BES definition in Order Nos. 773 and 773-A and concluded that individual wind turbine generators should be included as part of the BES. The SDT is not challenging this conclusion, but rather is addressing the applicability of standards on a requirement-by-requirement basis as necessary to account for the unique characteristics of dispersed generation. Thus, the applicability of requirements to individual generating units may be unnecessary except in cases where a common mode issue exists that could lead to a loss of a significant number of units or the entire ~~facility~~Facility in response to a transmission system event.

[17] "*Electricity Markets and Variable Generation Integration*,"~~,~~ WECC, January 6, 2011. https://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/WECC%20Whitepaper%20-%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf

3.3 Drafting Team Efforts

The SDT ~~is~~ approached~~ing~~ this project in multiple phases. First, after a thorough discussion of the new definition of the BES, the SDT reviewed each standard, as shown in Appendix A, at a high level to recommend changes that would promote consistent applicability for dispersed ~~generation~~ power producing resources through the entire set of Reliability Standards. This review provided the type of changes proposed, the justification for the changes, and the priority of the changes. The SDT ~~has~~ documented its review in this ~~white paper~~White Paper, which will continue to be updated throughout the SDT efforts. The second phase, currently in progress, includes revising standards where necessary~~, addressing high priority issues first,~~ and supporting the balloting and commenting process.

3.3.1 Scope of Standards Reviewed

Initially, the focus of the standards review was on standards and requirements applicable to GOs and GOPs. However, during discussions, a question was raised to the SDT whether consideration is necessary for other requirements that affect the interaction of a Balancing Authority (BA), Transmission Operator (TOP), or Reliability Coordinator (RC) with individual BES Elements. For example, a requirement that states “an RC shall monitor BES Elements” may unintentionally affect the RC operator due to the ~~newly~~ revised BES definition. As such, the SDT ~~decided to take~~took a high-level look at all standards adopted by the NERC Board of Trustees (Board) or approved by FERC to ensure this issue was~~is~~ not significant.

All standards that were reviewed are listed in Appendix A along with the status of the standards as of ~~July 2~~December 11, 2014. ~~There are several new standards included in Appendix A that the drafting team will review and provide updates within this paper if applicability changes are needed. These standards include IRO-001-3, IRO-005-4, MOD-031-1, TOP-002-3, and TOP-003-2.~~ The fields in Appendix A include the following:~~;~~

- List of standards (grouped by approval status)
- Approval status of the standards which include
  - Subject to Enforcement
  - Subject to Future Enforcement
  - Filed and Pending Regulatory Approval
  - Pending Regulatory Filing
  - Designated for Retirement (2 standards – MOD-024-1 and MOD-025-1 – officially listed as Filed and Pending Regulatory Approval but will be superseded by MOD-025-2)
  - In concurrent active development
- Indication of change or additional review necessary

The SDT also reviewed, at a high-level, any approved regional standards. In cases where a change is recommended to a regional standard, the SDT will notify the affected Region. In addition, the SDT is prepared to provide recommendations to other active NERC standard development efforts, where appropriate[SC1].

Status	Number of Standards	Number of Standards to be Addressed (Standard, RSAW, Guidance or Further Review)
NERC Standards	**166**	**27**
Subject to Enforcement	101	12
Subject to Future Enforcement	20	5
Pending Regulatory Approval	28	4
Pending Regulatory Filing	7	0
Designated for Retirement	2	0
Proposed for Remand	8	6
Region-specific Standards (*Out of Scope)	**17**	**4**
Subject to Enforcement	15	3
Subject to Future Enforcement	2	1
Pending Regulatory Approval	0	0
Grand Total	**183**	**31**

3.3.2 Reliability Objectives~~Principles~~

The SDT used the following Reliability Objectives~~Principles~~ to review the standards:

- Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
- The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
- Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
- Plans for ~~emergency~~ Emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
- Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
- Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
- The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
- Bulk power systems shall be protected from malicious physical or cyber attacks.

3.3.3 Prioritization Methodology

The SDT established a prioritization ~~for~~ tothe review and modify~~ication of~~ applicability changes recommended to NERC standards and requirements. The SDT evaluated each requirement to identify the appropriate applicability to support reliability of the BPS.~~ After the SDT identified a standard or requirement where changes to the applicability are warranted, it performed a prioritization.~~ In general, any standard or requirement ~~in which~~ the SDT ~~believes modifications are~~ determined required modification was ~~required has been~~ assigned a high, medium, or low priority. The standards and requirements priorities were established as follows:

- High priority was assigned so that standard or requirement changes would be made quickly enough to avoid an entity having to expend inordinate resources prematurely to comply with a standard or requirement that, after appropriate modification, would not be applicable to that entity.

- Medium priority was assigned if significant effort and resources with no appreciable reliability benefit would be required by an entity to be compliant; and
- Low priority was assigned to other changes that may need to be made to further ensure requirements add to reliability, but are not perceived as a significant compliance burden.

The prioritization of each recommendation is identified in Appendix B.

- List of standards (grouped by priority)
- Approval status of the standards (same designations as used in Appendix A)
- Recommendation of changing the ~~applicability section~~Applicability Section of the standard or by changing the applicability for specific requirements
- Recommendation of which applicability options should apply.

~~The SDT remains on schedule to complete its recommendations on the high-priority standards by the November 2014 NERC Board of Trustees (Board) meeting, with recommendations on the medium- and low-priority standards by the February 2015 Board meeting.~~

~~5~~4 Technical Discussion

This section provides a review of each group of standards, focusing on the impact of the BES definition on reliability and compliance efforts. This discussion proposes a resolution for each standard, whether it is a change in the ~~applicability section~~Applicability Section or in a specific requirement, clarification in a guidance document, or no action needed.

~~5.1~~4.1 BAL

The group of BAL standards focuses primarily on ensuring the Balancing Authority (BA) has the awareness, ability, and authority to maintain the frequency and operating conditions within its BA Area. Only two standards in this group affect GO and/or GOP, and no BAL standard reviewed affected the interaction of a host BA, TOP, or RC with individual BES Elements.

~~5.1.1~~4.1.1 BAL-005 — Automatic Generation Control

The purpose of this standard, as it applies to GOPs, is to ensure that all facilities electrically synchronized to the Interconnection are included within the metered boundary of a BA Area so that balancing of resources and demand can be achieved. Ensuring the ~~facility~~Facility as a whole is within a BA Area ensures the individual units are included. *Therefore, the applicability of the BAL-005 standard does not need to be changed for dispersed power producing~~generation~~ resources.*

~~5.1.2~~4.1.2 BAL-001-TRE-1 — Primary Frequency Response in the ERCOT Region

The purpose of BAL-001-TRE-1 standard is to maintain Interconnection steady-state frequency within defined limits. This standard should be modified to clarify the applicability for dispersed ~~generation~~ power producing resources to the total plant level to ensure coordinated performance. However, this is a regional standard and not part of the SDT scope. *The SDT will communicate this recommendation to the relevant Region.*

~~5.2~~4.2 COM

The COM[18] standards focus on communication between the RC, BAs, TOPs, and GOPs. The only requirements in any of the current or future enforceable standards that apply to the GOP are clearly intended to apply to the individual GOP registered functional entity (i.e., requires communication between GOPs, TOPs, BAs, and RCs), not the constituent Elements it operates. Consequently, there is no need to differentiate the GOPs obligation for dispersed ~~generation~~ power producing resources from any other resources. *Therefore, the applicability of the COM-001-2, COM-002-2a, and COM-002-4 standards that were reviewed do not need to be changed for dispersed ~~generation~~ power producing resources*[SC2].

~~5.3~~4.3 EOP

The EOP standards focus on emergency operations and reporting. The standards that apply to GO and/or GOP entities are EOP-004 and EOP-005. No EOP standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

~~5.3.1~~4.3.1 EOP-004 — Event Reporting

The purpose of this standard is to improve the reliability of the BES by requiring the reporting of events by Responsible Entities. The requirements of this standard that apply to the GO and GOP appear to apply to the individual GO and GOP registered functional entity, not the constituent elements. *The SDT has considered whether there is a need to differentiate dispersed power producing~~generation~~ resources from any other GO and/or GOP resource and determined that no changes are required to the standard.*

~~5.3.2~~4.3.2 EOP-005 — System Restoration from Blackstart Resources

EOP-005 ensures plans are in place to restore the grid from a de-energized state. The requirements that apply to a GOP are primarily for individual generation facilities designated as Blackstart Resources, with one requirement to participate in restoration exercises or simulations as requested by the RC. The inclusion of Blackstart Resources is already identified in the BES definition through Inclusion I3. The expectation is that all registered GOPs will participate in restoration exercises as requested by its RC. *Therefore, the applicability of EOP-005 does not need to be changed for dispersed power producing~~generation~~ resources.*

~~5.4~~4.4 FAC

The FAC standards focus on establishing ratings and limits of the ~~facility~~Facility and interconnection requirements to the BES. Several standards apply to GOs and/or GOPs. No FAC standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

~~5.4.1~~4.4.1 FAC-001 — Facility Connection Requirements

Requirements R2 and R3 of this standard apply to any GO that has an external party applying for interconnection to the GO's existing Facility in order to connect to the transmission system. This scenario

~~[18] Note that COM-002-2a and COM-002-3, which are Pending Regulatory Filing, will be replaced by COM-002-4.~~

is uncommon and there is no precedent for applicability of this standard to dispersed *power producing*~~generation~~ resources known to the SDT. Current practice primarily includes the GO stating that they will comply with the standard if this scenario is ever realized. This standard allows the GO to specify the conditions that must be met for the interconnection of the third-party, thus providing inherent flexibility to tailor the requirements specifically for the unique needs of the Facility. ~~Furthermore, in 2012, the NERC Integration of Variable Generation Task Force (IVGTF) provided some suggested changes[19] to this standard for the next version. The IVGTF report included modifying requirements to this standard as well as recommended guidance for considering integration of variable generation plants. The recommendations on Standards changes are technology neutral and independent of the type of generation.~~ ~~*For these reasons*~~*Therefore, the applicability of FAC-001 does not need to be changed for dispersed power producing resources.*

~~5.4.2~~4.4.2 FAC-002 — Coordination of Plans for New Facilities

The purpose of FAC-002 is to ensure coordinated assessments of new facilities. The requirement applicable to GOs requires coordination and cooperation on assessments to demonstrate the impact of new facilities on the interconnected system and to demonstrate compliance with NERC standards and other applicable requirements. The methods used to demonstrate compliance are independent of the type of generation and are typically completed at the point of interconnection. *Therefore, the applicability of FAC-002 does not need to be changed for dispersed power producing~~generation~~ resources.*

~~5.4.3~~4.4.3 FAC-003 — Transmission Vegetation Management

The purpose of this standard is to ensure programs and efforts are in place to prevent vegetation-related outages. This standard applies equally to dispersed generation facilities and traditional Facilities in both applicability and current practices, as it pertains to overhead transmission lines of applicable generation interconnection Facilities. *Therefore, the applicability of FAC-003 does not need to be changed for dispersed power producing~~generation~~ resources.*

~~5.4.4~~4.4.4 FAC-008 — Facility Ratings

FAC-008 ensures ~~facility~~Facility ratings used in the planning and operation of the BES are established and communicated. The ~~facility~~Facility ratings requirement has historically been applicable to dispersed power producing resources and current practices associated with compliance are similar to traditional generation facilities. There is inherent flexibility in the standard requirements for the GO to determine the methodology utilized in determining the ~~facility~~Facility ratings.

To identify the ~~facility~~Facility rating of a dispersed power producing resource the analysis of the entire suite of ~~facility~~Facility components is necessary to adequately identify the minimum and maximum Facility Rating and System Operating Limits, and thus there would be no differentiation between the compliance obligations between dispersed power producing resources and traditional generation. *The SDT believes the industry and Regions would benefit from additional guidance on FAC-008 in the form of changes to add a technical guidance section to the standard ~~the corresponding RSAW~~, ~~and as follows:~~or other guidance.*

[19] ~~http://www.nerc.com/files/2012_IVGTF_Task_1-3.pdf~~

~~The applicability language in the standard is somewhat ambiguous as this language can potentially be interpreted to exclude the non-BES equipment from the generator to the low side terminals of the step up transformer (transformer with at least one winding at 100 kV). The use of the term "main step-up transformer" in Requirements R1 and R2 refers to the final GSU (the last transformer(s) used exclusively for stepping up the generator output) prior to the point of interconnection or, when the point of interconnection is before the GSU, the GSU that steps up voltage to transmission line voltage level and is used strictly as a delineation point between Requirements R1 and R2. In an attempt to address this potential misinterpretation, the SDT provides the following clarifications:~~

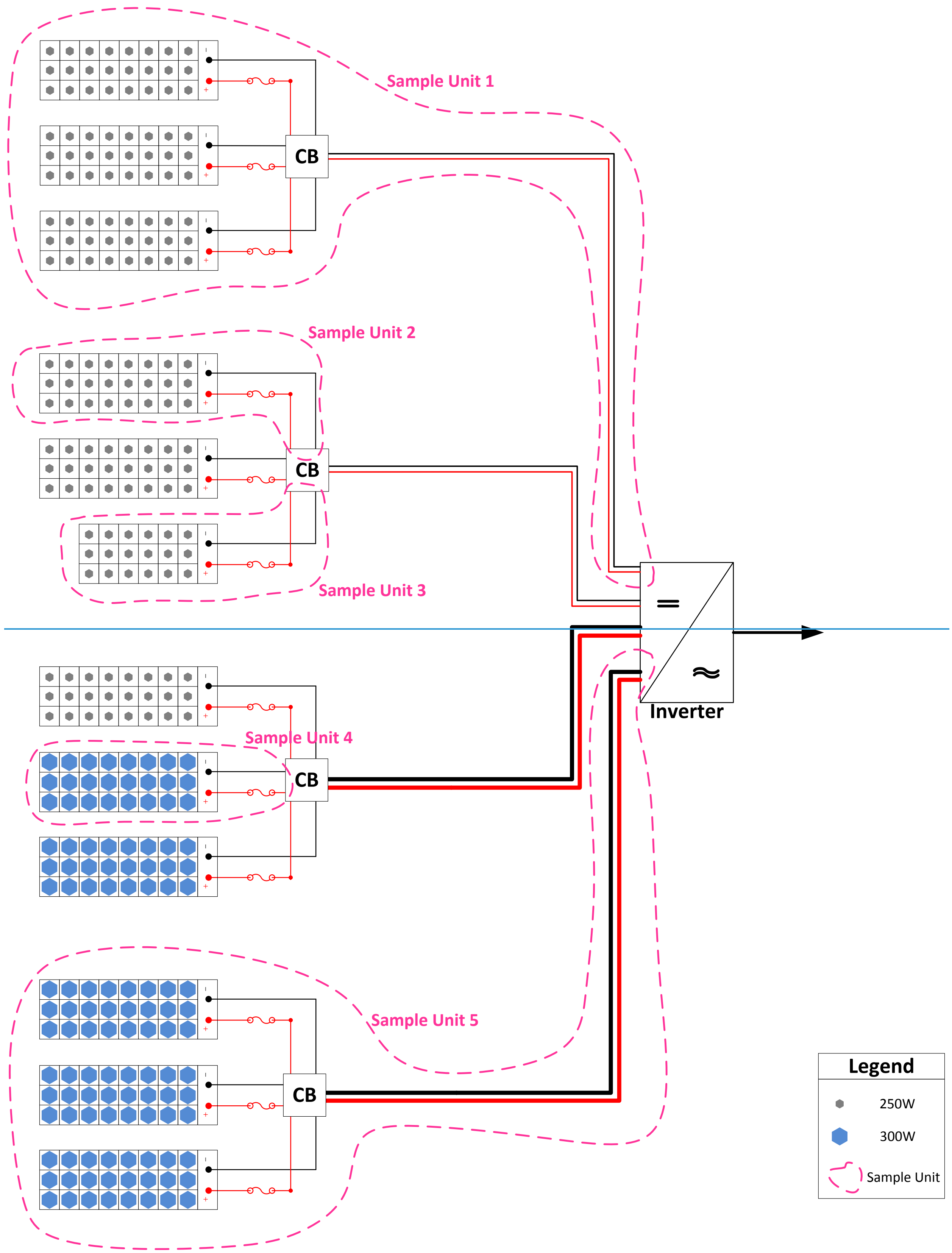
0. ~~Referencing the NERC Glossary definition of Facility Ratings, identifies that the voltage, current, frequency, real or reactive power flow through a facility must not violate the equipment rating of any equipment of the facility (which is subjected to the voltage, current, etc.). With this definition, it is clear that each component or piece of equipment must be reviewed to ensure the ratings are not exceeded, and that applicable documentation be maintained.~~

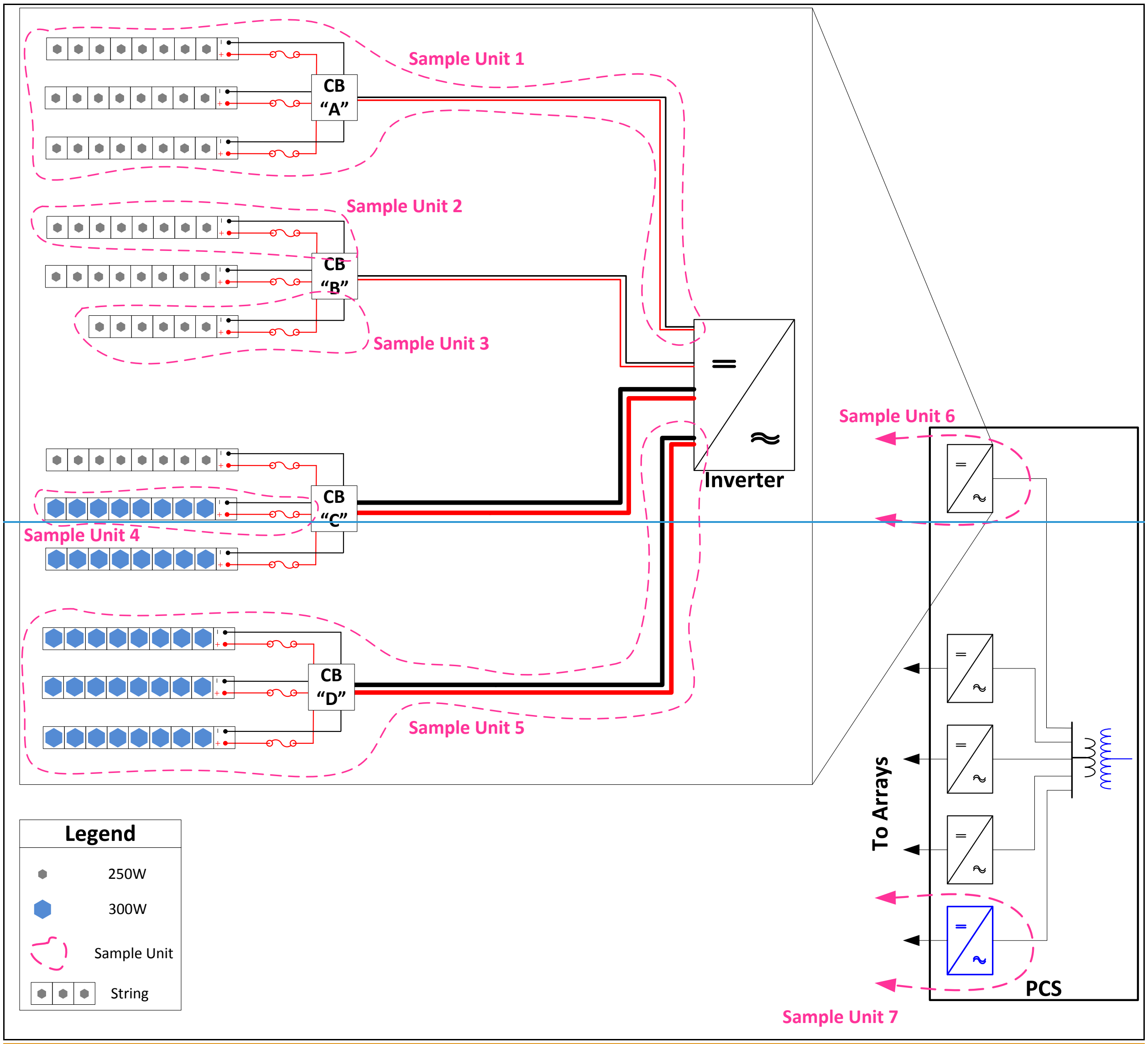
0. ~~The use of the term "Facilities" in the phrase "…determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer…" could potentially be interpreted to refer only to BES Facilities because the Glossary definition of "Facility" includes the term "Bulk Electric System Element," and for dispersed power producing facilities could leave out portions of the facility, specifically the collection system. However, the intent of the standard is to address the Facility Ratings of all electrical equipment from the generator to the point of interconnection.~~

~~As an example for solar arrays provide ratings for Array or Panel, DC Cables (Positive and Negative), Combiner Boxes, Inverters, as well as associated breakers, Instrument transformers (CVT's, PT's), disconnect switches, and relays, etc. This is shown in Figure X~~

~~If there are multiple chains with the same ratings then only one path needs to be provided with a "multiplier number" for that piece of equipment when calculating the facility rating value. For example; A facility is comprised of 50 identical inverter units rated at 2 MW, which have identical Combiner Box, Module string and module compositions/orientations; then the Facility rating would be 50*2 MW = 100 MW.~~

~~In order to identify the most limiting component of the facility a complete analysis of every component in a sample unit must be conducted. This will include analysis from the generator (solar module or WTG) up through the high side terminals of the main step-up transformer. In an effort to simplify this analysis, grouping of identical equipment configurations into a sample unit is an accepted industry practice. The following discussion and diagrams provide an explanation of how this could be accomplished for dispersed power producing resources (wind and solar).~~

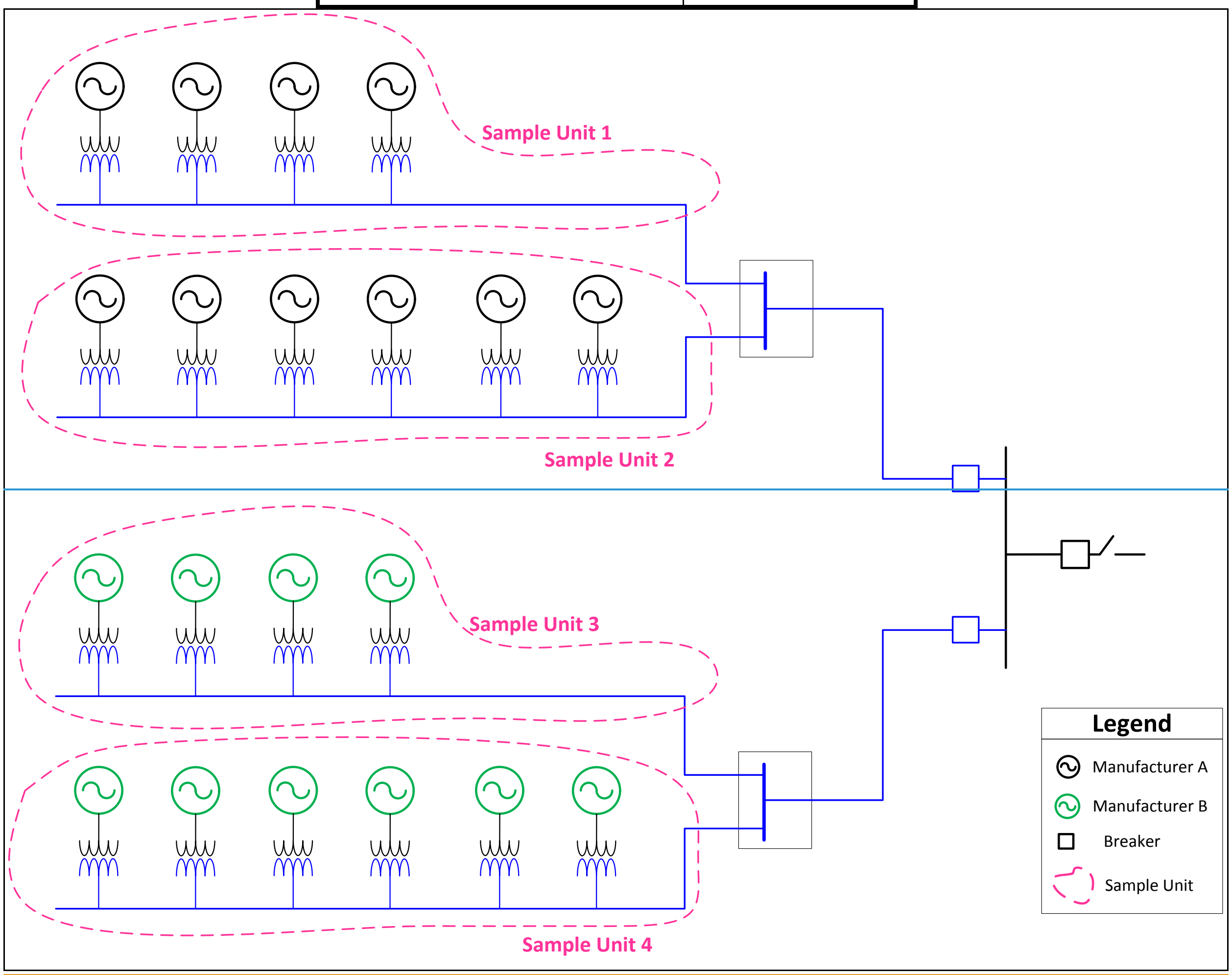

Sample Unit 1
CB
Sample Unit 2
CB
Sample Unit 3
Inverter
Sample Unit 4
CB
Sample Unit 5
CB
Legend
250W
300W
Sample Unit



~~Once a complete analysis of the sample unit is completed, this sample unit can then be referred to in future rating analysis without repeating the complete sample unit analysis.~~

~~Element~~	~~Unit Rating~~	~~#Units in system~~	~~Rating~~
~~Sample Unit #1 (Nine strings of Eight 250 W modules each)~~	~~18 kW~~	~~1~~	~~18 kW~~
~~Sample Unit #2 (Three strings of Eight 250 W modules)~~	~~6 kW~~	~~3~~	~~18 kW~~
~~Sample Unit #3 (Three Strings of Six 250 W modules)~~	~~4.5 kW~~	~~1~~	~~4.5 kW~~
~~Sample Unit #4 (Three strings of Six 300 W modules)~~	~~5.4 kW~~	~~2~~	~~10.8 kW~~
~~Sample Unit #5 (Nine strings of Eight 300 W modules each)~~	~~21.6 kW~~	~~1~~	~~21.6 kW~~
~~Sample Unit #6~~	~~80 kW~~	~~4~~	~~320 kW~~
~~Sample Unit #7~~	~~80 kW~~	~~1~~	~~80 kW~~

~~Element~~	~~Multiplier~~
~~15-module String~~	~~100~~
~~Fuses~~	~~100~~
~~Positive/Negative DC Cables~~	~~200~~
~~Combiner Box~~	~~20~~
~~Inverter~~	~~20~~
~~Transformer~~	~~1~~



~~Figure Y: Sample Unit Representation (Wind)~~

~~5.45~~4.5 INT

The INT standards provide BAs the authority to monitor power interchange between BA Areas. No INT standard is applicable to the GO or GOP, or affects the interaction of a host BA, TOP, or RC with individual BES Elements. *Therefore, the applicability of the INT standards do not need to be changed for dispersed power producing~~generation~~ resources.*

~~5.46~~4.6 IRO

The IRO standards provide RCs their authority. There are three IRO Standards that apply directly to GO and/or GOP entities. There are three standards that apply to the interaction of the RC with individual BES Elements. No other IRO standard reviewed affected the interaction of a host BA, TOP, or RC with GOs and/or GOPs.

~~5.46.1~~4.6.1 IRO-001 — Reliability Coordination — Responsibilities and Authorities[20]

The purpose of these standards and their requirements as applicable to a GOP is to ensure RC directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements, or cannot be physically implemented. If a GOP is unable to follow a RC directive they are to inform the RC immediately of such.

Directives from RCs have been traditionally applied to the dispersed power producing resource at the aggregate ~~facility~~ Facility level when they are related to either active power or voltage, such as an output reduction or the provision of voltage support. When such directives are not specific to any one Element within the Facility, it is up to the GOP to determine the appropriate method to achieve the desired result of the directive consistent with other applicable NERC Reliability Standards. When an RC directive specifies a particular Element or Elements at the GOP's ~~facility~~Facility, it is the expectation and requirement that the GOP will act as directed, so long as doing so does not violate safety, equipment, or regulatory or statutory requirements or cannot be physically implemented. For example, a directive could specify operation of a particular circuit breaker at a GOP Facility. *For these reasons, the applicability of IRO-001 does not need to be changed for dispersed ~~generation~~ power producing resources.*

~~5.46.2~~4.6.2 IRO-005 — Reliability Coordination — Current Day Operations[21]

The purpose of this standard and its requirements as it relates to GOPs is to ensure when there is a difference in derived limits the BES is operated to the most limiting parameter. A difference in derived limits can occur on any Element and therefore any limitation of the applicability of this standard may create a reliability gap. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of IRO-005 does not need to be changed for dispersed ~~generation~~ power producing resources.*

~~5.46.3~~4.6.3 IRO-010 — Reliability Coordinator Data Specification and Collection

The purpose of this standard and its requirement(s) as it relates to GOs and GOPs is to ensure data and information specified by the RC is provided. As each RC area is different in nature, up to and including the tools used to ensure the reliability of the BPS, a 'one size fits all' approach is not appropriate. This Reliability Standard allows for the RC to specify the data and information required from the GO and/or the GOP, based on what is required to support the reliability of the BPS. *Therefore, the applicability of IRO-010 does not need to be changed for dispersed power producing~~generation~~ resources.*

[20] Note that IRO-001-3, which is adopted by the ~~NERC BOT~~Board, was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

[21] Note that applicability to GOPs has been removed in IRO-005-4, which is adopted by the Board~~NERC BOT~~. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

~~5.47~~4.7 MOD

The MOD group of standards ensures consistent modeling data requirements and reporting procedures. The MOD standards provide a path for Transmission Planners (TPs) and Planning Coordinators (PCs) to reach out to entities for specific modeling information, if required. The SDT believes the existing and proposed modeling standards are sufficient for modeling dispersed ~~generation~~ power producing resources. However, due to the unique nature of dispersed power producing~~generation~~ resources and an effort to bring consistency to the models, *the SDT believes additional guidance on the MOD standards would be beneficial and will communicate its determination to ~~with other groups responsible for developing such guidance, e.g.,~~ the NERC Planning Committee ~~and the MOD-032 SDT, in their determination of whether developing guidelines would be valuable to support accurate modeling~~*.

~~5.47.1~~4.7.1 MOD-010 — Steady-State Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-010 does not need to be changed for dispersed generation resources.*

~~5.47.2~~4.7.2 MOD-012 — Dynamics Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-012 does not need to be changed for dispersed generation resources.*

~~5.47.3~~4.7.3 MOD-024-1 — Verification of Generator Gross and Net Real Power Capability

This standard was established to ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2.[22] *Therefore, the applicability of MOD-024-1 does not need to be changed for dispersed generation resources.*

~~5.47.4~~4.7.4 MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability

This standard was established to ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2. *Therefore, the applicability of MOD-025-1 does not need to be changed for dispersed generation resources.*

~~5.47.5~~4.7.5 MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net Real and Reactive Power capability is available for planning models used to assess BES reliability. This standard is appropriate for and includes specific provisions for dispersed generation resources to ensure changes in

[22] MOD-024-1 and MOD-025-1 are ~~NERC BOT~~ Board Adopted but not subject to enforcement. They are commonly followed as good utility practice.

capabilities are reported. *Therefore, the SDT ~~will recommend~~is further evaluating whether to ~~revisions~~ revise ~~to 4.2.3~~ the applicability of the standard to align the language with the revised BES definition.*

~~5.47.6~~4.7.6 MOD-026 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

This standard provides for verification of models and data for voltage control functions. This standard is appropriate for dispersed generation resources. ~~to ensure changes in control systems and capabilities are reported.~~ *~~However~~Originally, the DGR SDT considered ~~recommends~~ clarifying the applicability ~~to ensure~~of the Facilities section ~~aligns with dispersed generation resources~~, however, upon further review, the DGR SDT recommends no change.*

~~5.47.7~~4.7.7 MOD-027 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

This standard was established to verify that the turbine/governor and frequency control model accurately represent generator unit Real Power response to system frequency variations. This standard is appropriate for dispersed generation resources ~~to ensure changes in control systems and capabilities are reported~~. *Originally, the DGR SDT considered clarifying the applicability of the Facilities section, however, upon further review, the DGR SDT recommends no change.~~However, the SDT recommends clarifying the applicability to ensure the Facilities section aligns with dispersed generation resources.~~*

~~5.47.8~~4.7.8 MOD-032 — Data for Power System Modeling and Analysis

The MOD-032 standard was established to ensure consistent modeling data requirements and reporting procedures for the planning horizon cases. The nature of dispersed generation resources is a challenge in modeling the steady-state and dynamic electrical properties of the individual components (e.g. individual units, collector system, interconnection components, etc.).

Models for dispersed ~~generation~~ power producing resources are typically proprietary and unique for each ~~facility~~Facility. Generic models exist for dynamic analysis that may provide sufficient accuracy in lieu of a ~~facility~~Facility-specific model. Some sections of the MOD-032 Attachment 1 pertain to modeling individual units, which may not be feasible. Guidance should be provided to show how to best model dispersed ~~generation~~ power producing resources. Such guidance should require modeling requirements for each type of dispersed power producing~~generation~~ resource within a ~~facility~~Facility and aggregate model for each reasonable aggregation point. *The applicability of MOD-032 does not need to be changed for dispersed ~~generation~~ power producing resources.*

~~5.48~~4.8 NUC

The requirements in standard NUC-001 — *Nuclear Plant Interface Coordination* individually define the applicability to Registered Entities, not to the Elements the entities own or operate. While it is unlikely any Elements that are part of a dispersed power producing~~generation~~ resource would be subject to an agreement required by this standard, limiting the applicability of this standard could create a reliability gap and thus, there is no need to differentiate applicability to dispersed generation resources. *Therefore, the applicability of the NUC standard does not need to be changed for dispersed ~~generation~~power producing resources.*

~~5.49~~4.9 PER

The PER standards focus on operator personnel training. The only requirements in any of the current or future enforceable standards that apply to the GOP is requirement R6 in PER-005-2 – *Operations Personnel Training*, and it is clearly intended to apply to the individual GOP registered functional entity that controls a fleet of generating facilities, not the constituent Elements it operates. As such, there is no need to differentiate dispersed power producing~~generation~~ resources from any other GOP resources. *Therefore, the applicability of the PER standards do not need to be changed for dispersed power producing~~generation~~ resources.*

~~5.50~~4.10 PRC

The PRC standards establish guidance to ensure appropriate protection is established to protect the BES.

~~5.50.1~~4.10.1 PRC-001-1.1 — System Protection Coordination

Requirement R1 requires GOPs to be familiar with the purpose and limitations of Protection System schemes applied in their area. The recently approved changes to the BES definition extend the applicability of this requirement. Often this familiarity is provided to GOP personnel through training on the basic concepts of relay protection and how it is utilized. The basic relaying concepts utilized in protection on the aggregating equipment at a dispersed generation site typically will not vary significantly from the concepts used in Protection Systems on individual generating units.

Requirement R2 requires that GOPs report protective relay or equipment failures that reduce system reliability. Protective System failures occurring within a single individual generating unit at a dispersed power producing~~generation~~ resource will not have any impact on overall system reliability and thus it should not be necessary for GOPs to report these failures to their TOP and host BA. Only failures of Protection Systems on aggregating equipment have the potential to impact BPS reliability and may require notification. When interpreted as stated above, no related changes should be required to the existing PRC-001-1 standard, as the BES definition changes do not have an impact on these requirements.

Requirement R3 requires GOPs to coordinate new protective systems. Coordinating new and changes to existing protective relay schemes should be applied to aggregating equipment protection only if a lack of coordination could cause unintended operation or non-operation of an interconnected entity's protection, thus potentially having an adverse impact to the BPS. Existing industry practice is to share/coordinate the protective relay settings on the point of interconnect (e.g. generator leads, radial generator tie-line, etc.) and potentially the main step-up transformer, but not operating (collection) buses, collection feeder, or individual generator protection schemes, as these Protection Systems do not directly coordinate with an interconnected utility's own Protection Systems. Relay protection functions such as under and overfrequency and under and overvoltage changes are independent of the interconnected utility's protective relay settings and the setting criteria are defined in PRC-024.

Requirement R5 requires GOPs to coordinate changes in generation, transmission, load, or operating conditions that could require changes in the Protection Systems of others. A GOP of a dispersed generation resource should be required to notify its TOP of changes to generation, transmission, load, or operating conditions on an aggregate ~~facility~~Facility level.

Project 2007-06 – System Protection Coordination and Project 2014-03 – Revisions to TOP and IRO Standards are presently revising various aspects of this standard or addressing certain requirements in other standards.

For these reasons, the DGR SDT ~~has~~ coordinated with the other SDTs currently reviewing this standard and ~~has~~ recommended revisions to Requirement R3.1 to indicate that coordination by a GOP with their TOP and host BA of new or changes to protection systems on individual generating units of dispersed power producing resources is not required. ~~account for the unique characteristics of dispersed power producing resources.~~

~~5.50.2~~4.10.2 PRC-001-2 — System Protection Coordination

The concerns addressed with PRC-001-1.1b are removed in PRC-001-2, which is adopted by the ~~NERC BOT~~Board. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-03 – Revisions to TOP and IRO Standards. This Standard version is not in effect and ~~will be~~was withdrawn ~~when the currently~~as the proposed versions of the TOP and IRO Reliability Standards included in Project 2014-3 effectively replace PRC-001-2 and other TOP standards ~~are filed at FERC~~[SC3]. *For this reason, no changes are required.*

~~5.50.3~~4.10.3 PRC-002-NPCC-01— Disturbance Monitoring
PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting

Requirements related to installation of Fault/Disturbance monitoring and/or sequence of events (SOE) recording capabilities on generating units and substation equipment which meet regional specific criteria may require installation of these capabilities on the aggregating equipment at a dispersed ~~generation~~ power producing resource ~~facility~~Facility, and also requires maintenance and periodic reporting requirements to their RRO. However, these requirements have been previously applicable to the aggregating equipment at these dispersed ~~generation~~ power producing resources, and these capabilities are not required to be installed on the individual generating units. The BES definition changes have no direct impact on applicability of these standards to dispersed ~~generation~~ power producing resources. *Therefore, the applicability of these standards do~~es~~ not need to be changed for dispersed ~~generation~~ power producing resources.*[23]

~~5.50.4~~4.10.4 PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations
PRC-004-3 — Protection System Misoperation Identification and Correction

Misoperation reporting per PRC-004 is currently a requirement applied on the aggregating equipment at applicable dispersed ~~generation~~ power producing resource sites meeting BPS criteria. The continuation of this analysis and reporting on the aggregating equipment by dispersed generation resource owners can provide value to BPS reliability and should remain in place. However, based on the experience of the SDT, there is minimal impact to BPS reliability for analyzing, reporting and developing Corrective Action Plans for each individual generating unit that trips at a dispersed ~~generation~~ power producing resource site, as the tripping of one or a small number of these units has no material impact to the BPS reliability.

[23] *See* NPCC CGS-005.

Additionally, reporting of Misoperations on each individual generating unit may result in substantial and unnecessary burdens on both the dispersed generation resource owner and the Regional Entities that review and track the resulting reports and Corrective Action Plan implementations. The SDT recognizes that many turbine technologies do not have the design capability of providing sufficient data for an entity to evaluate whether a Misoperation has occurred. Furthermore, dispersed power producing~~generation~~ resources by their nature result in each individual generating unit potentially experiencing varied power system parameters (e.g., voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities design. This limits the ability to determine whether an individual unit correctly responded to a system disturbance.

However, the SDT maintains that 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 large number of the individual generation resources (aggregate nameplate rating of greater than 75 MVA) incorrectly operated or failed to operate as designed during a system event. As such, if a trip aggregating to greater than 75 MVA occurs in response to a system disturbance, the SDT ~~proposes~~ proposed requiring analysis and reporting of Misoperations of individual generating units for which the root cause of the Protection System operation(s) affected an aggregate rating of greater than 75 MVA of BES Facilities. Note that the SDT selected the 75 MVA nameplate threshold for consistency and to prevent confusion.

The SDT was also ~~is~~ concerned with the applicability of events where one or more individual units tripped and the root cause of the operations was identified as a setting error. In this case, the requirements of PRC-004 would be applicable for any individual units where identical settings were applied on the Protection Systems of like individual generation resources identified under Inclusion I4 of the BES definition.

The SDT ~~concludes~~ concluded that it is not necessary under PRC-004 to analyze each individual Protection System Misoperation affecting individual generating units of a dispersed ~~generation~~ power producing resource.~~, but is concerned with the potential for unreported Misoperations involving a common mode failure of multiple individual generating units as described.~~ *The SDT ~~has~~ recommended changes to the applicability of this standard to require misoperation analysis on individual generating units at a dispersed ~~generation~~ power producing resource site, only for events affecting greater than 75MVA aggregate nameplate; the SDT ~~feels~~ determined that this will ensure that common mode failure scenarios and their potential impact on BPS reliability are appropriately addressed. The SDT's recommended changes passed industry ballot on November 6, 2014, and were approved by the Board on November 13, 2014, and are currently pending regulatory approval*.

~~5.50.5~~4.10.5 PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

Dispersed ~~generation~~ power producing resource sites typically would not be associated with a WECC Major Transfer Path or Remedial Action Scheme (RAS), and thus would not be affected by PRC-004-WECC-1. If a site were to be involved with one of these paths or schemes, it is likely that associated protection or RAS equipment would be located on the aggregating equipment rather than the individual generating units. As such, the BES definition changes may have an impact on applicability of this standard to dispersed ~~generation~~ power producing resources. This standard should be modified to clarify the applicability for dispersed generation resources; however, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT ~~will~~ recommends that the relevant Region ~~communicate this recommendation to the~~ evaluate the standard for modification~~relevant Region~~.*

~~5.50.6~~4.10.6 PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing

The SDT recognizes that PRC-005-1.1b will be phased out beginning in early 2015. Therefore, the SDT recommends only guidance on PRC-005-1.1b rather than suggesting language changes to the standard. *Therefore, the SDT does not recommend revising the applicability of this standard ~~does not need to be changed~~ for dispersed generation resources, ~~as~~ rather, the SDT provided ~~guidance has been provided in the form of recommended changes~~recommendations for revisions to the applicable RSAW to NERC staff, which NERC has implemented after consultation with the Regions.*

~~5.50.7~~4.10.7 PRC-005-2 — Protection System Maintenance
PRC-005-3 — Protection System and Automatic Reclosing Maintenance
PRC-005-4~~x~~ — Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance~~Protection System Maintenance and Testing: Sudden Pressure Relays~~

The aggregated capability of the individual generating units may in some cases contribute to the reliability of the BPS; as such, there can be reliability benefit from ensuring certain BES equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in PRC-005[24]. When evaluated individually, however, the generating units themselves do not have the same impact on BPS reliability as the system used to aggregate the units. The unavailability or failure of any one individual generating unit would have a negligible impact on the aggregated capability of the ~~facility~~Facility; this would be irrespective to whether the dispersed generation resource became unavailable due to occurrence of a legitimate fault condition or due to a failure of a control system, protective element, dc supply, etc.

The protection typically utilized in these generating units includes elements which would automatically remove the individual unit from service for certain internal or external conditions, including an internal fault in the unit. These units typically are designed to provide generation output at low voltage levels, (i.e., less than 1000 V). Should these protection elements fail to remove the generating unit for this scenario, the impacts would be limited to the loss the individual generating unit and potentially the next device upstream in the collection system of the dispersed ~~generation~~ power producing resource. However, this would still only result in the loss of a portion of the aggregated capability of the ~~facility~~Facility, which would be equally likely to occur due to a scenario in which a fault occurs on the collection system.

Internal faults on the low voltage system of these generating units would not be discernible on the interconnected transmission systems, as this is similar to a fault occurring on a typical utility distribution

~~[24] Reliability Standard PRC-005 is currently being revised as part of Project 2007-17.3 – Protection System Maintenance and Testing – Phase 3, available here: http://www.nerc.com/pa/Stand/Pages/Project-2007-17_3-Protection-System-Maintenance-and-Testing-Phase-3.aspx. Any proposed changes to the PRC-005 Reliability Standard will be coordinated with this project. Project 2007-17.1 is considering technical changes and Project 2014-01 will consider any applicability change.~~

system fed from a substation designed to serve customer load. It is important to note that the collection system equipment (e.g., breakers, relays, etc.) used to aggregate the individual units may be relied upon to clear the fault condition in both of the above scenarios, which further justifies ensuring portions of the BES collection equipment is maintained appropriately.

For this reason, activities such as Protection System maintenance on each individual generating unit at a dispersed generation ~~facility~~Facility would not provide any additional reliability benefits to the BPS, but Protection System maintenance on facilities where generation aggregates to 75 MVA or more would. The SDT proposes that the scope of PRC-005 be limited to include only the protection systems that operate at a point of aggregation above 75 MVA nameplate rating. If the aggregation point occurs at a component in the collection system, then the protection systems associated with this component would be in scope. *The SDT has recommended changes to the Applicability ~~section~~ Section (Facilities) of PRC-005-2, -3, and -4~~X~~ to indicate that maintenance activities should only apply on the aggregating equipment at or above the point where the aggregation exceeds 75 MVA. The SDT's recommended applicability changes to PRC-005-2 and PRC-005-3 were approved by the Board on November 13, 2014. The SDT's recommended applicability changes to PRC-005-4 were posted for an initial ballot period that ends on January 22, 2014.*

~~5.50.9~~4.10.8 PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding PRC-006-SERC -1 — Automatic Underfrequency Load Shedding Requirements

The regional specific PRC-006 standards deviate from the PRC-006-1 standard in that they have specific requirements for GOs. In particular, the NPCC version requires that GOs set their underfrequency tripping to meet certain criteria to ensure reliability of the BPS. Typically a dispersed generation resource site may have underfrequency protection on both the aggregating equipment (i.e., collection buses or feeders) as well as the individual generating units. Were this standard only to apply to aggregating equipment, the net impact to the BPS should a system disturbance occur may still result in a loss of significant generating capacity should each of the individual generating units trip for the event. Therefore it may be appropriate to include the individual generating units at a dispersed generation resource site as subject to this standard. The standard could be interpreted this way as written, but further clarification in the standard language may be considered. While this standard may need to be modified to clarify the applicability for dispersed generation resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.~~Therefore, the SDT will communicate this recommendation to the relevant Region~~*.

The SERC version of PRC-006 requires GOs to provide, upon request, certain under and overfrequency related setpoints and other related capabilities of the site relative to system disturbances. It may be appropriate to include the capabilities of the individual generating units at a dispersed generation resource site when providing this information; however, it may be sufficient to provide only the capabilities of a single sample unit within a site as these units are typically set identically. This would be in addition to any related capabilities or limitations of the aggregating equipment as well. This may be accomplished by providing clarifications in the requirements sections. While this standard may need to be modified to clarify the applicability for dispersed ~~generation~~ power producing resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.~~Therefore, the SDT will communicate this recommendation to the relevant Region~~*.

~~5.50.10~~4.10.9 PRC-015 — Special Protection System Data and Documentation
PRC-016 — Special Protection System Misoperations
PRC-017 — Special Protection System Maintenance and Testing

Relatively few dispersed ~~generation~~ power producing resources own or operate Special Protection Systems (SPSs); however, they do exist and therefore need to be evaluated for applicability based on the revised BES definition. The vast majority of these SPSs involve the aggregating equipment (transformers, collection breakers, etc.) and not the individual generating units. The SPSs are installed to protect the reliability of the BPS, and as such the aggregated response of the site (e.g., reduction in output, complete disconnection from the BES, etc.) is critical, not the response of individual generating units. *Therefore, the applicability of these standards does not need to be changed for dispersed ~~generation~~ power producing resources.*

~~5.50.11~~4.10.10 PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Dispersed ~~generation~~ power producing resources typically utilize a site level voltage control scheme that directs the individual generating units to adjust their output to meet the voltage requirements at an aggregate ~~facility~~Facility level. In these cases the individual generating units will simply no longer respond once they are "maxed out" in providing voltage or reactive changes, but also need to be properly coordinated with protection trip settings on the aggregating equipment to mitigate risk of tripping in this scenario. For those facilities that solely regulate voltage at the individual unit, these facilities also need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. The applicability in PRC-019-1 (section 4.2.3) includes a "Generating plant/~~-~~Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating)." *Therefore, the DGR SDT revised the Facilities section of the standard to clarify that facilities which solely regulate voltage at the individual generating unit are subject to this standard's requirements. The SDT's recommended applicability changes to PRC-019-1 were posted for an initial comment and ballot period scheduled to close December 22, 2014.*

~~5.50.12~~4.10.11 PRC-023— Transmission Relay Loadability

Dispersed power producing~~generation~~ resources in some cases contain facilities and Protection Systems that meet the criteria described in the ~~applicability section~~Applicability Section (e.g., load responsive phase Protection System on transmission lines operated at 200 kV or above); however, in the majority of cases these lines are radially connected to the remainder of the BES and are excluded from the standard requirements of PRC-023-3. While certain entities with dispersed ~~generation~~ power producing resources are required to meet the requirements of PRC-023 on components of their aggregating equipment (e.g., main step-up transformers, interconnecting transmission lines) the standard is not applicable to the individual generating units, as the individual generating units are addressed in PRC-025. The BES definition changes have no direct impact on the applicability of this standard to dispersed ~~generation~~ power producing resources. *Therefore, the applicability of thi~~e~~s~~e~~ standard~~s~~ does not need to be changed for dispersed ~~generation~~ power producing resources.*

~~5.50.13~~4.10.12 PRC-024— Generator Frequency and Voltage Protective Relay Settings

If the individual generating units at a dispersed ~~generation~~ power producing resource were excluded from this requirement, it is possible large portions or perhaps the entire output of a dispersed ~~generation~~ power producing resource site may be lost during certain system disturbances, negatively impacting BES reliability. The SDT has determined it is appropriate to require that Protection System settings applied on both the individual generating units and aggregating equipment (including any Protection Systems applied on non-BES portions of the aggregating equipment), are set within the "no-trip zone" referenced in the requirements to maintain reliability of the BES. However, for the purpose of compliance evidence, the SDT believes it should be sufficient for an entity to provide evidence for a single sample generating unit within a site rather than providing documentation for each individual unit, providing the entity used that methodology to set its protection systems for all the units, rather than providing documentation for each individual unit. This would be in addition to any Protection System settings evidence for the aggregating equipment. *The SDT therefore recommended changes to the standard requirements to ensure these requirements are applied to the individual power producing resources as well as all equipment, potentially including non-BES equipment, from the individual power producing resource up to the point of interconnection and communicated compliance evidence requirement considerations to NERC staff for RSAW development. The SDT's recommended applicability changes to PRC-024 were posted for an initial comment and ballot period scheduled to close December 22, 2014.*

~~*The SDT therefore recommended changes to the standard requirements addressing the scope of applicability as stated above and will recommend changes to the RSAW to address documentation options.*~~

~~5.50.14~~4.10.13 PRC-025— Generator Relay Loadability

The Protection System utilized on individual generating units at a dispersed ~~generation~~ power producing ~~facility~~Facility may include load-responsive protective relays and thus would be subject to the settings requirements listed in this standard. Were this standard only to apply to aggregating equipment, the net impact to the BPS should a system disturbance occur, may be a loss of significant generating capacity should each of the individual generating units trip for the event. The SDT has determined it is appropriate to require that Protection System settings applied on both the individual generating units at a dispersed ~~generation~~ power producing resource site as applicable to this standard. However, for the purpose of compliance evidence, the SDT believes it should be sufficient for an entity to provide evidence for a single sample generating unit within a site rather than providing documentation for each individual unit, providing the entity used that methodology to set its protection systems for all the units, rather than providing documentation for each individual unit. This would be in addition to any Protection System settings evidence for the aggregating equipment. As such the SDT recommends the RSAW be modified as stated above. *The SDT recommended n~~N~~o changes to the standard ~~are required~~; however, the DGR SDT communicated compliance evidence requirement considerations to NERC staff for RSAW development. ~~is recommending changes to the RSAW to clarify compliance evidence requirements.~~*

~~5.51~~4.11 TOP

The TOP standards provide TOPs their authority. There are four TOP standards that apply directly to GO and GOP entities. The TOP standards as they relate to GOs/GOPs ensure RCs and TOPs can issue directives to the GOP, and the GOP follows such directives. They also ensure GOPs render all available emergency assistance as requested. Finally, they require GO/GOPs to coordinate their operations and outages and provide data and information to the BA and TOP. No TOP standard refers to the interaction of a host BA, TOP, or RC with individual BES Elements.

~~5.51.1~~4.11.1 TOP-001-1a — Reliability Responsibilities and Authorities

This standard as it applies to GOPs is reviewed at the requirement level, with only one change recommended.

~~5.51.1.1~~4.11.1.1 Requirement R3

The purpose of requirement R3 as it relates to GOPs is to ensure the RC and TOP reliability directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow a RC or TOP reliability directive they are to inform the RC or TOP immediately of such. The requirement is applicable to the registered functional entity, not the constituent Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed ~~generation~~ power producing resources from any other GOP resources, and no change to this requirement is needed.*

~~5.51.1.2~~4.11.1.2 Requirement R6

The purpose of requirement R6 as it relates to GOPs is to ensure all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements. The requirement is applicable to the registered functional entity, not the constituent Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed ~~generation~~ power producing resources from any other GOP resources, and no change to this requirement is needed.*

~~5.51.1.3~~4.11.1.3 Requirement R7

The purpose of requirement R7 as it relates to GOPs is to ensure BES facilities are not removed from service without proper notification and coordination with the TOP and, when time does not permit such prior notification and coordination, notification and coordination shall occur as soon as reasonably possible. This is required to avoid burdens on neighboring systems. It should be noted that the purpose of this standard is to keep the TOP informed of all generating ~~facility~~Facility capabilities in case of an emergency. It is assumed that required notification and coordination from the GOP to the TOP would be done in real-time and through verbal communication media. The concern here is how to apply this to a dispersed power producing~~generation~~ resource ~~facility~~Facility. The SDT recommends that the GOP report at the aggregate ~~facility~~Facility level to the TOP any generator outage above 20 MVA for dispersed power producing~~generation~~ resource facilities. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition, which addresses only generating units greater than 20 MVA.
- TOP-002-2.1b Requirement R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the ~~facility~~Facility (e.g., 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.

Dispersed power producing~~generation~~ resource outages should be reported as X MW out of Y MW are available. *Therefore, the SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for generator outages greater than 20 MVA.*

~~5.5~~~~1.2~~4.11.2 TOP-001-~~2~~3— Transmission Operations[25]

The purpose of this standard as it relates to GOPs is to ensure TOP directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow a TOP directive they are to inform the TOP immediately of such. It directs the TOP to issue directives and as such the TOP may provide special requirements for dispersed power producing~~generation~~ resources for its unique capabilities. ~~Note that while this standard is adopted by the NERC BOT, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-03 – Revisions to TOP and IRO Standards.~~ *The SDT recommends that Project 2014-3 provide direction for a dispersed power producing~~generation~~ resource to be only reported at the aggregate facility level. If TOP-001-1a R7 is reintroduced, then the recommendation provided above should be included in their efforts.*

~~5.5~~~~1.3~~4.11.3 TOP-002-2.1b — Normal Operations Planning[26]

This TOP standard has five requirements applied to GOPs. Several modifications are recommended below, and the SDT recommends that the most effective and efficient way to accomplish this is through modification of the Applicability ~~section~~ Section of this standard.

~~5.5~~~~1.3.1~~4.11.3.1 Requirement R3

The purpose of requirement R3 as it relates to GOPs is to ensure a GOP's current day, next-day and seasonal operations are coordinated with its ~~Host~~ host BAs and TSP. This requirement relates to planned operations at a generator and does not include unplanned operations such as forced or emergency operations. The SDT recommends that this requirement be applied at the aggregate ~~facility~~Facility level for dispersed power producing resources. For example, forecasting available MW at the aggregated ~~facility~~Facility level is currently one method used. The SDT does not see any reliability gap in that would prompt this team to apply R3 to any point less than the dispersed power resource aggregated ~~facility~~Facility level.

The SDT has not found or been made aware of a reliability gap that would prompt this team to apply R3 to any point less than the dispersed power resource aggregated ~~facility~~Facility level and recommends such modification to the applicability of this requirement.

~~5.5~~~~1.3.2~~4.11.3.2 Requirement R13

The purpose of requirement R13 as it relates to GOPs is to ensure Real Power and Reactive Power capabilities are verified as requested by the BA and TOP. The SDT believes a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT is

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[25] Note that TOP-001-2 was adopted by the Board and remanded by FERC. TOP-001-2 is currently under revision as part of Project 2014-03 – Revisions to TOP and IRO Standards, and was posted for additional ballot period that is scheduled to close January 7, 2015 as TOP-001-3.

[26] The GOP applicability is removed in TOP-002-3, which was adopted by the ~~NERC BOT~~Board. However, TOP-002-3 was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

recommending that this requirement be applied at the aggregate ~~facility~~Facility level for dispersed power producing resources for the following reasons:

- Due to the nature, amount of individual generators at a dispersed power producing -resource, internal Real Power losses, and natural inductance and capacitance of dispersed power resource system connected in series, verification of real and reactive capabilities should be conducted at the dispersed power producing resource aggregate ~~facility~~Facility level. Performing verification in this manner will provide an actual net real and reactive capability, which would be seen by both the BA and TOP. In addition, performing verification in this manner is also consistent with operating agreements such as an interconnection agreement, which the dispersed power resource has with the TOP and BA.
- MOD-025-2 also provides that verification for any generator <20MVA may be completed on an individual unit basis or as a "group." Reporting capability at the aggregated ~~facility~~Facility level is consistent with the MOD-025-2 provision for group verification.

The SDT recommends a modification to the applicability of this requirement at the aggregated ~~facility~~Facility level for dispersed power producing resources.

~~5.51.3.3~~4.11.3.3 Requirement R14

The purpose of requirement R14 as it relates to GOPs is to ensure BAs and TOPs are notified of changes in real output capabilities without any intentional time delay. It should be noted that the purpose of this requirement is to address unplanned changes in real output capabilities. It is assumed the required notification and coordination from the GOP to the BA and TOP would be done in real-time and through verbal communication media. The concern here is how to apply this to dispersed power producing resources. The SDT recommends that the GOP notify at the aggregate ~~facility~~Facility level to the TOP any unplanned changes in real output capabilities above 20 MVA. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition which includes generating units greater than 20MVA.
- TOP-002-2.1b R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the ~~facility~~Facility (e.g. 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.

Dispersed generation resources changes in real output capabilities should be reported as X MW out of Y MW are available. *The SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for unplanned outages greater than 20 MVA.*

~~5.51.3.4~~4.11.3.4 Requirement R15

The purpose of requirement R15 as it relates to GOPs is to ensure BAs and TOPs are provided a forecast (e.g., seven day) of expected Real Power. The SDT believes this requirement as requested by the BA or TOP is being applied at the aggregate ~~facility~~Facility level for dispersed power producing resources.

Based on the SDT's experience, expected Real Power forecasts (e.g. 5 or 7 forecast) for a dispersed power producing resource has been traditionally coordinated with the BA and TOP at the aggregate ~~facility~~Facility level for dispersed power producing resources. *Therefore, the SDT recommends that R15 be applied at the aggregate ~~facility~~Facility level for dispersed power resources and as such, modification to the applicability of this requirement is necessary.*

~~5.51.3.5~~4.11.3.5 Requirement R18

The purpose of requirement R18 as it relates to a GOP is to ensure uniform line identifiers are used when referring to transmission facilities of an interconnected network. The standard applies to transmission facilities of an interconnected network, which would not apply to any Elements within the dispersed generation ~~facility~~Facility. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

~~5.51.4~~4.11.4 TOP-003-1— Planned Outage Coordination[27]

This TOP Standard has three requirements applied to GOPs. Modification to one of these requirements is recommended.

~~5.51.4.1~~4.11.4.1 Requirement R1

The purpose of requirement R1 as it relates to GOPs is to ensure TOPs are provided planned outage information on a daily basis for any scheduled generator outage >50MW for the next day. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

~~5.51.4.2~~4.11.4.2 Requirement R2

The purpose of requirement R2 as it relates to GOPs is to ensure all voltage regulating equipment scheduled outages are planned and coordinated with affected BAs and TOPs. A modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT recommends that this requirement be applied at the aggregate ~~facility~~Facility level for dispersed power producing resources.

Based on the SDT's experience, scheduled outages of voltage regulating equipment at a dispersed power producing resource has been traditionally provided to the BA and TOP at the aggregate ~~facility~~Facility level for dispersed power producing resources. Outages of voltage regulating equipment at a dispersed power producing resource are coordinated typically as a reduction in Reactive Power capabilities, specifying whether it is inductive, capacitive or both. Additionally, automatic voltage regulators that do not necessarily provide Reactive Power, but direct the actions of equipment that do supply Reactive Power, are typically coordinated at the aggregate ~~facility~~Facility level as they usually are the master controller for all voltage regulating equipment at the ~~facility~~Facility. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap, which would prompt this team to apply R2 to any point less than the dispersed power producing r~~r~~esource aggregated ~~facility~~Facility level and as ~~in~~ such, ~~feels~~ determined a*

[27] ~~Note that TOP-003-2, which is adopted by the NERC BOT, was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.~~

modification to the applicability of this requirement is necessary for dispersed power producing resources.

~~5.51.4.3~~4.11.4.3 Requirement R3

The purpose of requirement R3 as it relates to GOPs is to ensure scheduled outages of telemetering and control equipment and associated communication channels are planned and coordinated among BAs and TOPs. Based on the SDT technical expertise, scheduled outages of telemetering and control equipment and associated communication channels at a dispersed power producing resource have been traditionally provided to the BA and TOP at the aggregate ~~facility~~Facility level for dispersed power producing resources. In addition, only scheduled outages of telemetering and control equipment and associated communication channels that can affect the BA and TOP are coordinated with the BA and TOP. *Therefore, the applicability of this requirement does not need to be changed for dispersed ~~generation~~ power producing resources.*

~~5.51.5~~4.11.5 TOP-006 — Monitoring System Conditions

The purpose of this standard as it relates to GOPs is to ensure BAs and TOPs know the status of all generation resources available for use as informed by the GOP. It should also be noted that the purpose of this standard is to ensure critical reliability parameters are monitored in real-time. It then can be extrapolated that the requirement, "GOP shall inform…," is done by sending dispersed power producing resource telemetry in real-time and through a digital communication medium, such as an ICCP link or RTU. The SDT feels a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT is recommending that this requirement be applied at the aggregate ~~facility~~Facility level for dispersed power producing resources for the following reasons:

- This is consistent with Inclusion I2 of the revised BES definition, which includes generating units greater than 20MVA. If removing <20MVA would cause a burden to the BPS, then the threshold for inclusion in the BES would have been less than 20MVA.
- Routine maintenance is frequently completed on a small portion of the entire ~~facility~~Facility (e.g. 2% of the generators are out of service on any given day) such as to not have a significant impact to the output capability of the ~~facility~~Facility. Additionally, it is not uncommon to have individual generating units at a dispersed power producing resource to go into a failure mode due to internal factors of the equipment, such as hydraulic fluid pressure tolerances, gearbox bearing thermal tolerances, etc. As such, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.
- As this standard requires real-time monitoring, this is most likely completed through a digital medium such as an ICCP link or RTU. The data that a dispersed power resource provides to the BA and TOP in real-time should include the aggregate active power output of the ~~facility~~Facility, among other telemetry points. These data specifications are usually outlined in interconnection agreements among the parties.

Based on the SDT technical expertise, BAs and TOPs are informed by the GOP of all generation resources available at the dispersed power producing resource at the aggregate ~~facility~~Facility level. Traditionally the dispersed power producing resources are providing the BA and TOP, at minimum, the following telemetry points in real-time: aggregate Real Power, aggregate Reactive Power and main high-side circuit breaker status. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap, which would prompt this team to apply these requirement to any point less than where the dispersed power producing resource aggregates and as in such, recommends a modification to the applicability of this requirement is necessary for dispersed power producing resources.*

~~5.52~~4.12 TPL

At the time of this paper, these standards do not affect GOs or GOPs directly. Input from GO or GOP entities is provided to transmission planning entities through the MOD standards. *Therefore, the applicability of the TPL standards does not need to be changed for dispersed ~~generation~~ power producing resources. ~~The SDT will continue to coordinate with other SDTs that consider changes that encompass new standards that may implicate potential power producing resource applicability changes.~~*

~~5.53~~4.13 VAR

The VAR standards exist to ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained. There are two VAR Standards that apply to GOs and/or GOPs. The voltage and/or reactive schedule provided by TOPs is specified to be at the point of interconnection or the point specified in the interconnection agreement.

~~5.53.1~~4.13.1 VAR-001 — Voltage and Reactive Control (WECC Regional Variance)

The purpose of this standard as it relates to GOPs in WECC is to ensure a generator voltage schedule is issued that is appropriate for the type of generator(s) at a specific ~~facility~~Facility. Additionally, it requires GOPs to have a methodology for how the voltage schedule is met taking into account the type of equipment used to maintain the voltage schedule. Based on the SDT technical expertise, voltage control and voltage schedule adherence for dispersed power producing resource occurs at the aggregate ~~facility~~Facility level. There is no need to differentiate dispersed generation resources from any other GOP resources. *Therefore, the applicability of VAR-001 does not need to be changed for dispersed generation resources.*

~~5.53.2~~4.13.2 VAR-002-2b — Generator Operation for Maintaining Network Voltage Schedules
VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

The purpose of these standards as they relate to GOs and GOPs is to ensure generators operate in automatic voltage control mode as required by the TOP voltage or reactive power schedule provided to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and reliability of the Interconnection. Based on the SDT technical expertise, voltage control and voltage schedule adherence for dispersed power producing resource occurs at the aggregate ~~facility~~Facility level and such guidance should be provided.

In addition, the voltage-controlling equipment and the methodology to ensure the ~~facility~~Facility has an automatic and dynamic response to ensure the TOP's instructions are maintained can be very different for each ~~facility~~Facility. It is implied in VAR-001-3 that each TOP should understand capabilities of the generation ~~facility~~Facility and the requirements of the transmission system to ensure a mutually agreeable solution/schedule is used.

~~5.53.3~~4.13.3 VAR-002-2b — Requirement R3.1 VAR-002-3 — Requirement R4

The purpose of these requirements is to ensure that a GOP notifies the TOP, within 30 minutes, any status and capability changes of any generator Reactive Power resource, including automatic voltage regulator, power system stabilizer or alternative voltage controlling device. Based on the experience of the SDT, status and capability changes is traditionally coordinated at the aggregate ~~facility~~Facility level point of interconnection. *Therefore, the SDT has recommended changes to the standard to clarify the applicability of VAR-002-2b R3.1 and VAR-002-3 R4 for dispersed power producing resources. These changes were successfully balloted in VAR-002-4 on November 6, 2014, and approved by the Board on November 13, 2014.*

~~5.53.5~~4.13.4 VAR-002-2b — Requirement R4 VAR-002-3 — Requirement R5

The purpose of these requirements is to ensure that Transmission Operators and Transmission Planners have appropriate information and provide guidance to the GOP in regards to Generator Operator's transformers to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and reliability of the Interconnection. Based on the experience of the SDT dispersed power producing resources individual generator transformers have traditionally been excluded from the requirements of VAR-002-2b R4 and VAR-002-3 R5, as they are not used to improve voltage performance on the Interconnection. As such, applicability should be limited to transformers with at least one winding at a voltage of 100kV or above. *Therefore, the SDT has recommended changes to the standard to clarify the applicability of VAR-002-2b R4 and VAR-002-3 R5 for dispersed generation resources. These changes were successfully balloted in VAR-002-4 on November 6, 2014, and approved by the Board on November 13, 2014.*

~~5.54~~4.14 CIP

~~5.54.1~~4.14.1 CIP v5[SC4]

The CIP standards are still under revision in Project 2014-02. The DGR SDT and the CIP SDT continue to coordinate revisions to the CIP standards, and will update this section to reflect the outcome of that effort at the appropriate time.

The CIP standards ensure physical and cyber security for BES Cyber Assets and BES Cyber Systems critical to the reliability and security of the BES. CIP-002 identifies critical assets or systems of a ~~facility~~Facility, while CIP-003 to CIP-011 depend on the outcome of the CIP-002 assessment to determine applicability.

~~The DGR SDT and the CIP SDT continued coordination of possible revisions to the CIP standards.~~ During the Project 2014-02 CIP Version 5 Revisions SDT first comment period, it received comments to modify CIP-003-6 in the ~~applicability section~~Applicability Section. The CIP SDT made drastic modifications to the second posting of CIP-003-6 to take into accounts all of the comments received, which was posted for an additional 45-day comment and ballot period on September 3, 2014.

At its September meeting, the DGR SDT had a focused discussion with the CIP SDT surrounding the technical nature of the dispersed power producing resources and how it relates to the CIP standards. The coordinating effort resulted in discussions of the revised CIP-003-6. As for that posted revised standard, the CIP SDT took the approach of including an Attachment 1 for Responsible Entities. The Attachment 1 requires elements to be developed in Responsible Entities' cyber security plan(s) for assets containing low impact BES Cyber Systems. The elements in CIP-003-6, Attachment 1 allow flexibility for the controls to be established for each of the main four elements below. The CIP SDT encourages observers of the DGR SDT to review the Attachment 1 in detail. Here is some information regarding the attachment.

Element 1: Security Awareness

The intent of the security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. It is up to the entity as to the topics and how it schedules these topics. The Responsible Entity should be able to produce the awareness material that was delivered and the delivery method(s) (posters, emails, topics at staff meetings, etc.) that were used. The SDT does not intend that the Responsible Entity must maintain lists of recipients and track the reception of the awareness material by personnel.

Element 2: Physical Security

The Responsible Entity has flexibility in the controls used to restrict physical access to low impact BES Cyber Systems at a BES asset using one or a combination of access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may utilize perimeter controls (e.g., fences with locked gates, guards, site access policies, etc.) and/or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses. User authorization programs and lists of authorized users are not required.

Element 3: Electronic Access Controls

Where Low Impact External Routable Connectivity (LERC) or Dial-up Connectivity exists, the Responsible Entity must document and implement controls that include the LERC and Dial-up Connectivity to the BES asset such that the low impact BES Cyber Systems located at the BES asset are protected. Two glossary terms are included in order to help clarify and simplify the language in Attachment 1. The SDT's intent in creating these terms is to avoid confusion with the similar concepts and requirements (ESP, EAP, ERC, EACMS) needed for high and medium impact BES Cyber Systems by utilizing separate terms that apply only to assets containing low impact BES Cyber Systems.

Element 4: Cyber Security Incident Response

The entity should have one or more documented cyber security incident response plans that include each of the topics listed. For assets that do not have LERC, it is not the intent to increase their risk by increasing the level of connectivity in order to have real-time monitoring. The intent is if in the normal course of business suspicious activities are noted at an asset containing low impact BES Cyber Systems, there is a cyber security incident response plan that will guide the entity through responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Therefore, the DGR SDT recommends that no changes be made to proposed CIP-003-6. CIP-002-5.1 needs to remain as is because entities must go through the process for identifying and categorizing its BES Cyber Systems and their associated BES Cyber Assets. The controls put in place for proposed CIP-

003-6, Attachment 1, are not burdensome, are realistic and achievable, and does not express undue compliance burden. In conclusion, the DGR SDT states that the reliability objective of these controls are adequate and the applicability of CIP-003-6 should not be modified.

The SDT states that the CIP Version 5 Revisions SDT should consider developing guidance documentation around the following areas:

- Low Impact BES Cyber Systems that must comply with a limited number of requirements, all located in CIP-003-5. The only technical requirement is R2, which will be modified during the current drafting activity to add clarity to the requirement. The SDT notes that the CIP Version 5 Revisions SDT should consider developing guidance around how this requirement relates to dispersed generation.
- Any programmable logic device that has the capability to shut down the plant within 15 minutes; and
- Remote access from third party entities into the SCADA systems that control the aggregate capacity of a ~~facility~~Facility should be assessed to determine if there is a need of any additional cyber security policies.

The SDT intends to recommend guidance for those companies that only operate their turbines from one central location. Individual Elements lumped into a BES Cyber System should be addressed. When operations are on a turbine-by-turbine basis, the SDT believes there should not be rigid controls in place. The inability to "swim upstream" should be addressed as well. Further, the guidance intends to address when manufacturers operate or have control of the SCADA environment to conduct troubleshooting and other tasks, and ensure that proper security is in place.

NERC staff has committed to facilitate communication between the SDT and the CIP Version 5 Revisions SDT as appropriate to ensure alignment and to develop language for guidance, coordinated between the two SDTs. *Therefore, the applicability of CIP standards does not need to be changed for dispersed generation resources.*

Appendix A: List of Standards

Appendix B: List of Standards Recommended for Further Review

Standard Number	Status	Further Review by SDT	Regional
BAL-001-1	Subject to Enforcement	No	No
BAL-001-TRE-1	Subject to Enforcement	Yes	Yes
BAL-002-1	Subject to Enforcement	No	No
BAL-002-WECC-2	Subject to Enforcement	No	Yes
BAL-003-0.1b	Subject to Enforcement	No	No
BAL-004-0	Subject to Enforcement	No	No
BAL-004-WECC-02	Subject to Enforcement	No	Yes
BAL-005-0.2b	Subject to Enforcement	No	No
BAL-006-2	Subject to Enforcement	No	No
BAL-502-RFC-02	Subject to Enforcement	No	Yes
CIP-002-3	Subject to Enforcement	No	No
CIP-003-3	Subject to Enforcement	No	No
CIP-004-3a	Subject to Enforcement	No	No
CIP-005-3a	Subject to Enforcement	No	No
CIP-006-3c	Subject to Enforcement	No	No
CIP-007-3a	Subject to Enforcement	No	No
CIP-008-3	Subject to Enforcement	No	No
CIP-009-3	Subject to Enforcement	No	No
COM-001-1.1	Subject to Enforcement	No	No
COM-002-2	Subject to Enforcement	No	No
EOP-001-2.1b	Subject to Enforcement	No	No
EOP-002-3.1	Subject to Enforcement	No	No
EOP-003-2	Subject to Enforcement	No	No
EOP-004-2	Subject to Enforcement	Yes	No
EOP-005-2	Subject to Enforcement	No	No
EOP-006-2	Subject to Enforcement	No	No
EOP-008-1	Subject to Enforcement	No	No
FAC-001-1	Subject to Enforcement	No	No
FAC-002-1	Subject to Enforcement	No	No
FAC-003-3	Subject to Enforcement	No	No
FAC-008-3	Subject to Enforcement	Yes	No
FAC-010-2.1	Subject to Enforcement	No	No
FAC-011-2	Subject to Enforcement	No	No
FAC-013-2	Subject to Enforcement	No	No
FAC-014-2	Subject to Enforcement	No	No
FAC-501-WECC-1	Subject to Enforcement	No	Yes
INT-004-3	Subject to Enforcement	No	No
INT-006-4	Subject to Enforcement	No	No
INT-009-2	Subject to Enforcement	No	No
INT-010-2	Subject to Enforcement	No	No
INT-011-1	Subject to Enforcement	No	No
IRO-001-1.1	Subject to Enforcement	No	No
IRO-002-2	Subject to Enforcement	No	No
IRO-003-2	Subject to Enforcement	No	No
IRO-004-2	Subject to Enforcement	No	No
IRO-005-3.1a	Subject to Enforcement	No	No
IRO-006-5	Subject to Enforcement	No	No
IRO-006-EAST-1	Subject to Enforcement	No	Yes
IRO-006-TRE-1	Subject to Enforcement	No	Yes
IRO-006-WECC-2	Subject to Enforcement	No	Yes
IRO-008-1	Subject to Enforcement	No	No
IRO-009-1	Subject to Enforcement	No	No
IRO-010-1a	Subject to Enforcement	No	No
IRO-014-1	Subject to Enforcement	No	No

Note: Make sure "Appendix A Source" is correct. This table will auto-populate.

Zeroes indicate missing value on "Appendix A Source".

IRO-015-1	Subject to Enforcement	No	No
IRO-016-1	Subject to Enforcement	No	No
MOD-001-1a	Subject to Enforcement	No	No
MOD-004-1	Subject to Enforcement	No	No
MOD-008-1	Subject to Enforcement	No	No
MOD-010-0	Subject to Enforcement	No	No
MOD-012-0	Subject to Enforcement	No	No
MOD-016-1.1	Subject to Enforcement	No	No
MOD-017-0.1	Subject to Enforcement	No	No
MOD-018-0	Subject to Enforcement	No	No
MOD-019-0.1	Subject to Enforcement	No	No
MOD-020-0	Subject to Enforcement	No	No
MOD-021-1	Subject to Enforcement	No	No
MOD-026-1	Subject to Enforcement	Yes	No
MOD-027-1	Subject to Enforcement	Yes	No
MOD-028-2	Subject to Enforcement	No	No
MOD-029-1a	Subject to Enforcement	No	No
MOD-030-2	Subject to Enforcement	No	No
NUC-001-2.1	Subject to Enforcement	No	No
PER-001-0.2	Subject to Enforcement	No	No
PER-003-1	Subject to Enforcement	No	No
PER-004-2	Subject to Enforcement	No	No
PER-005-1	Subject to Enforcement	No	No
PRC-001-1.1	Subject to Enforcement	Yes	No
PRC-002-NPCC-01	Subject to Enforcement	No	Yes
PRC-004-2.1a	Subject to Enforcement	Yes	No
PRC-004-WECC-1	Subject to Enforcement	Yes	Yes
PRC-005-1.1b	Subject to Enforcement	Yes	No
PRC-006-1	Subject to Enforcement	No	No
PRC-006-SERC-01	Subject to Enforcement	Yes	Yes
PRC-008-0	Subject to Enforcement	No	No
PRC-010-0	Subject to Enforcement	No	No
PRC-011-0	Subject to Enforcement	No	No
PRC-015-0	Subject to Enforcement	No	No
PRC-016-0.1	Subject to Enforcement	No	No
PRC-017-0	Subject to Enforcement	No	No
PRC-018-1	Subject to Enforcement	No	No
PRC-021-1	Subject to Enforcement	No	No
PRC-022-1	Subject to Enforcement	No	No
PRC-023-3	Subject to Enforcement	No	No
PRC-025-1	Subject to Enforcement	Yes	No
TOP-001-1a	Subject to Enforcement	Yes	No
TOP-002-2.1b	Subject to Enforcement	Yes	No
TOP-003-1	Subject to Enforcement	Yes	No
TOP-004-2	Subject to Enforcement	No	No
TOP-005-2a	Subject to Enforcement	No	No
TOP-006-2	Subject to Enforcement	Yes	No
TOP-007-0	Subject to Enforcement	No	No
TOP-007-WECC-1a	Subject to Enforcement	No	Yes
TOP-008-1	Subject to Enforcement	No	No
TPL-001-0.1	Subject to Enforcement	No	No
TPL-002-0b	Subject to Enforcement	No	No
TPL-003-0b	Subject to Enforcement	No	No
TPL-004-0a	Subject to Enforcement	No	No
VAR-001-4	Subject to Enforcement	No	No

VAR-002-3	Subject to Enforcement	Yes	No
VAR-002-WECC-1	Subject to Enforcement	No	Yes
VAR-501-WECC-1	Subject to Enforcement	No	Yes
BAL-003-1	Subject to Future Enforcement	No	No
CIP-002-5.1	Subject to Future Enforcement	No	No
CIP-003-5	Subject to Future Enforcement	No	No
CIP-004-5.1	Subject to Future Enforcement	No	No
CIP-005-5	Subject to Future Enforcement	No	No
CIP-006-5	Subject to Future Enforcement	No	No
CIP-007-5	Subject to Future Enforcement	No	No
CIP-008-5	Subject to Future Enforcement	No	No
CIP-009-5	Subject to Future Enforcement	No	No
CIP-010-1	Subject to Future Enforcement	No	No
CIP-011-1	Subject to Future Enforcement	No	No
CIP-014-1	Subject to Future Enforcement	No	No
EOP-010-1	Subject to Future Enforcement	No	No
FAC-001-2	Subject to Future Enforcement	No	No
FAC-002-2	Subject to Future Enforcement	No	No
MOD-025-2	Subject to Future Enforcement	Yes	No
MOD-032-1	Subject to Future Enforcement	Yes	No
MOD-033-1	Subject to Future Enforcement	No	No
NUC-001-3	Subject to Future Enforcement	No	No
PER-005-2	Subject to Future Enforcement	No	No
PRC-005-2	Subject to Future Enforcement	Yes	No
PRC-006-NPCC-1	Subject to Future Enforcement	Yes	Yes
PRC-019-1	Subject to Future Enforcement	Yes	No
PRC-024-1	Subject to Future Enforcement	Yes	No
TPL-001-4	Subject to Future Enforcement	No	No
BAL-001-2	Pending Regulatory Approval	No	No
BAL-002-1a	Pending Regulatory Approval	No	No
COM-001-2	Pending Regulatory Approval	No	No
COM-002-4	Pending Regulatory Approval	No	No
MOD-001-2	Pending Regulatory Approval	No	No
MOD-011-0	Pending Regulatory Approval	No	No
MOD-013-1	Pending Regulatory Approval	No	No
MOD-014-0	Pending Regulatory Approval	No	No
MOD-015-0	Pending Regulatory Approval	No	No
MOD-031-1	Pending Regulatory Approval	No	No
PRC-002-1	Pending Regulatory Approval	No	No
PRC-003-1	Pending Regulatory Approval	No	No
PRC-004-3	Pending Regulatory Approval	Yes	No
PRC-005-3	Pending Regulatory Approval	Yes	No
PRC-012-0	Pending Regulatory Approval	No	No
PRC-013-0	Pending Regulatory Approval	No	No
PRC-014-0	Pending Regulatory Approval	No	No
PRC-020-1	Pending Regulatory Approval	No	No
TOP-006-3	Pending Regulatory Approval	Yes	No
TPL-001-3	Pending Regulatory Approval	No	No
TPL-002-2b	Pending Regulatory Approval	No	No
TPL-003-2a	Pending Regulatory Approval	No	No
TPL-004-2	Pending Regulatory Approval	No	No
TPL-005-0	Pending Regulatory Approval	No	No
CIP-002-3b	Pending Regulatory Filing	No	No
CIP-003-3a	Pending Regulatory Filing	No	No

CIP-007-3b	Pending Regulatory Filing	No	No
COM-002-2a	Pending Regulatory Filing	No	No
IRO-001-4	Pending Regulatory Filing	No	No
IRO-002-4	Pending Regulatory Filing	No	No
IRO-008-2	Pending Regulatory Filing	No	No
IRO-010-2	Pending Regulatory Filing	No	No
IRO-014-3	Pending Regulatory Filing	No	No
IRO-017-1	Pending Regulatory Filing	0	No
TOP-002-4	Pending Regulatory Filing	Yes	No
TOP-003-3	Pending Regulatory Filing	Yes	No
IRO-001-3	*See Project 2014-03	Yes	No
IRO-002-3	*See Project 2014-03	No	No
IRO-005-4	*See Project 2014-03	Yes	No
IRO-014-2	*See Project 2014-03	No	No
PRC-001-2	*See Project 2014-03	Yes	No
TOP-001-2	*See Project 2014-03	Yes	No
TOP-002-3	*See Project 2014-03	Yes	No
TOP-003-2	*See Project 2014-03	Yes	No
MOD-024-1	Designated for Retirement	No	No
MOD-025-1	Designated for Retirement	No	No
0	0	0	No
0	0	0	No
0	0	0	No
0	0	0	No
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0	0	0	No
0	0	0	No
0	0	0	No
0	0	0	No
0	0	0	No
0	0	0	No
0	0	0	No
0	0	0	No
0	0	0	No
0	0	0	No

Status	Number of Standards	Number of Standards to be Addressed (Standard, RSAW, Guidance or Further Review)
NERC Standards	**168**	**24**
Subject to Enforcement	98	13
Subject to Future Enforcement	24	5
Pending Regulatory Approval	24	3
Pending Regulatory Filing	12	3
Designated for Retirement	2	0
Proposed for Remand	8	0
Region-specific Standards (*Out of Scope)	**15**	**4**
Subject to Enforcement	14	3
Subject to Future Enforcement	1	1
Pending Regulatory Approval	0	0
Grand Total	**183**	**28**

Note: Make sure "Appendix A Source" is complete. This table will auto-populate.

Priority	Standard Number	Area To Change	Target Applicability
High	PRC-004-2.1a	Applicability Section	Misoperations affecting >75MVA
High	PRC-004-3	Applicability Section	Misoperations affecting >75MVA
High	PRC-005-1.1b	Guidance	Point where aggregates to >75MVA
High	PRC-005-2	Applicability Section	Point where aggregates to >75MVA
High	PRC-005-3	Applicability Section	Point where aggregates to >75MVA
High	VAR-002-3	Applicability Section& Footnote	Aggregate Facility Level for Voltage Control; Transmission voltage GSUs
Medium	EOP-004-2	No Action	NA
Medium	FAC-008-3	Guidance	Individual BES Resources /Elements to Include Aggregating Equipment
Medium	IRO-017-1	TBD	TBD
Medium	MOD-025-2	No Action	NA
Medium	MOD-026-1	No Action	NA
Medium	MOD-027-1	No Action	NA
Medium	MOD-032-1	No Action	NA
Medium	PRC-001-1.1	Applicability Section	Aggregate Facility Level
Medium	PRC-019-1	Applicability Section	Individual BES Resources/Elements
Medium	PRC-024-1	By Requirement	Individual BES Resources /Elements to Include Aggregating Equipment
Medium	PRC-025-1	Guidance	Individual BES Resources /Elements to Include Aggregating Equipment
Medium	TOP-001-1a	No Action	NA
Medium	TOP-002-2.1b	Applicability Section	Aggregate Facility Level
Medium	TOP-002-4	TBD	TBD
Medium	TOP-003-1	By Requirement	Aggregate Facility Level
Medium	TOP-003-3	TBD	TBD
Medium	TOP-006-2	No Action	NA
Medium	TOP-006-3	TBD	TBD
Low	BAL-001-TRE-1	Applicability Section	Aggregate Facility Level
Low	PRC-004-WECC-1	Applicability Section	Point where aggregates to >75MVA
Low	PRC-006-NPCC-1	By Requirement	Individual BES Resources/Elements
Low	PRC-006-SERC-01	By Requirement	Individual BES Resources/Elements
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0	0	w cells. Ensure rest aligns with the pap	0
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0	0	0	0

Note: Make sure "Appendix B Source" is correct. This table will auto-populate.

Zeroes indicate missing value on "Appendix B Source".

Status	Standard	FURTHER REVIEW	REG	Title	ste	reg	ste no reg	ste reg	stfe	reg	sfte no reg	sfte reg	pra	reg	pra no reg	pra reg	prf	reg	prf no reg	prf reg
Subject to Enforcement	BAL-001-1	No		Real Power Balancing Control Performance	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	BAL-001-TRE-1	Yes	R	Primary Frequency Response in the ERCOT Region	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	BAL-002-1	No		Disturbance Control Performance	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	BAL-002-WECC-2	No	R	Contingency Reserve	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	BAL-003-0.1b	No		Frequency Response and Bias	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	BAL-004-0	No		Time Error Correction	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	BAL-004-WECC-02	No	R	Automatic Time Error Correction (ATEC)	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	BAL-005-0.2b	No		Automatic Generation Control	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	BAL-006-2	No		Inadvertent Interchange	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	BAL-502-RFC-02	No	R	Planning Resource Adequacy Analysis, Assessment and Documentation	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	CIP-002-3	No		Cyber Security — Critical Cyber Asset Identification	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	CIP-003-3	No		Cyber Security — Security Management Controls	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	CIP-004-3a	No		Cyber Security — Personnel & Training	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	CIP-005-3a	No		Cyber Security — Electronic Security Perimeter(s)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	CIP-006-3c	No		Cyber Security — Physical Security of Critical Cyber Assets	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	CIP-007-3a	No		Cyber Security — Systems Security Management	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	CIP-008-3	No		Cyber Security — Incident Reporting and Response Planning	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	CIP-009-3	No		Cyber Security — Recovery Plans for Critical Cyber Assets	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	COM-001-1.1	No		Telecommunications	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	COM-002-2	No		Communications and Coordination	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	EOP-001-2.1b	No		Emergency Operations Planning	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	EOP-002-3.1	No		Capacity and Energy Emergencies	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	EOP-003-2	No		Load Shedding Plans	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	EOP-004-2	Yes		Event Reporting	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	EOP-005-2	No		System Restoration from Blackstart Resources	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	EOP-006-2	No		System Restoration Coordination	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	EOP-008-1	No		Loss of Control Center Functionality	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	FAC-001-1	No		Facility Connection Requirements	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	FAC-002-1	No		Coordination of Plans For New Generation, Transmission, and End-User Facilities	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	FAC-003-3	No		Transmission Vegetation Management	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	FAC-008-3	Yes		Facility Ratings	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	FAC-010-2.1	No		System Operating Limits Methodology for the Planning Horizon	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	FAC-011-2	No		System Operating Limits Methodology for the Operations Horizon	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	FAC-013-2	No		Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	FAC-014-2	No		Establish and Communicate System Operating Limits	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	FAC-501-WECC-1	No	R	Transmission Maintenance	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	INT-004-3	No		Dynamic Transfers	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	INT-006-4	No		Evaluation of Interchange Transactions	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	INT-009-2	No		Implementation of Interchange	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	INT-010-2	No		Interchange Initiation and Modification for Reliability	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	INT-011-1	No		Intra-Balancing Authority Transaction Identification	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	IRO-001-1.1	No		Reliability Coordination — Responsibilities and Authorities	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	IRO-002-2	No		Reliability Coordination — Facilities	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	IRO-003-2	No		Reliability Coordination — Wide-Area View	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	IRO-004-2	No		Reliability Coordination — Operations Planning	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	IRO-005-3.1a	No		Reliability Coordination — Current Day Operations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	IRO-006-5	No		Reliability Coordination — Transmission Loading Relief (TLR)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	IRO-006-EAST-1	No	R	Transmission Loading Relief Procedure for the Eastern Interconnection	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	IRO-006-TRE-1	No	R	IROL and SOL Mitigation in the ERCOT Region	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	IRO-006-WECC-2	No	R	Qualified Transfer Path Unscheduled Flow (USF) Relief	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	IRO-008-1	No		Reliability Coordinator Operational Analyses and Real-time Assessments	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0

Subject to Enforcement	IRO-009-1	No		Reliability Coordinator Actions to Operate Within IROLs	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	IRO-010-1a	No		Reliability Coordinator Data Specification and Collection	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	IRO-014-1	No		Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	IRO-015-1	No		Notifications and Information Exchange Between Reliability Coordinators	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	IRO-016-1	No		Coordination of Real-time Activities Between Reliability Coordinators	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-001-1a	No		Available Transmission System Capability	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-004-1	No		Capacity Benefit Margin	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-008-1	No		Transmission Reliability Margin Calculation Methodology	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-010-0	No		Steady-State Data for Modeling and Simulation of the Interconnected Transmission System	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-012-0	No		Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-016-1.1	No		Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-017-0.1	No		Aggregated Actual and Forecast Demands and Net Energy for Load	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-018-0	No		Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-019-0.1	No		Reporting of Interruptible Demands and Direct Control Load Management	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-020-0	No		Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-021-1	No		Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-026-1	Yes		Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-027-1	Yes		Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-028-2	No		Area Interchange Methodology	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-029-1a	No		Rated System Path Methodology	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	MOD-030-2	No		Flowgate Methodology	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	NUC-001-2.1	No		Nuclear Plant Interface Coordination	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PER-001-0.2	No		Operating Personnel Responsibility and Authority	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PER-003-1	No		Operating Personnel Credentials	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PER-004-2	No		Reliability Coordination — Staffing	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PER-005-1	No		System Personnel Training	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-001-1.1	Yes		System Protection Coordination	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-002-NPCC-01	No	R	Disturbance Monitoring	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	PRC-004-2.1a	Yes		Analysis and Mitigation of Transmission and Generation Protection System Misoperations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-004-WECC-1	Yes	R	Protection System and Remedial Action Scheme Misoperation	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	PRC-005-1.1b	Yes		Transmission and Generation Protection System Maintenance and Testing	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-006-1	No		Automatic Underfrequency Load Shedding	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-006-SERC-01	Yes	R	Automatic Underfrequency Load Shedding Requirements	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	PRC-008-0	No		Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-010-0	No		Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-011-0	No		Undervoltage Load Shedding System Maintenance and Testing	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-015-0	No		Special Protection System Data and Documentation	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-016-0.1	No		Special Protection System Misoperations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-017-0	No		Special Protection System Maintenance and Testing	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-018-1	No		Disturbance Monitoring Equipment Installation and Data Reporting	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-021-1	No		Under-Voltage Load Shedding Program Data	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-022-1	No		Under-Voltage Load Shedding Program Performance	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-023-3	No		Transmission Relay Loadability	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	PRC-025-1	Yes		Generator Relay Loadability	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	TOP-001-1a	Yes		Reliability Responsibilities and Authorities	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	TOP-002-2.1b	Yes		Normal Operations Planning	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	TOP-003-1	Yes		Planned Outage Coordination	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	TOP-004-2	No		Transmission Operations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	TOP-005-2a	No		Operational Reliability Information	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	TOP-006-2	Yes		Monitoring System Conditions	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0

Subject to Enforcement	TOP-007-0	No		Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	TOP-007-WECC-1a	No	R	System Operating Limits	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	TOP-008-1	No		Response to Transmission Limit Violations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	TPL-001-0.1	No		System Performance Under Normal (No Contingency) Conditions (Category A)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	TPL-002-0b	No		System Performance Following Loss of a Single Bulk Electric System Element (Category B)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	TPL-003-0b	No		System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	TPL-004-0a	No		System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	VAR-001-4	No		Voltage and Reactive Control	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	VAR-002-3	Yes		Generator Operation for Maintaining Network Voltage Schedules	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Subject to Enforcement	VAR-002-WECC-1	No	R	Automatic Voltage Regulators (AVR)	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Enforcement	VAR-501-WECC-1	No	R	Power System Stabilizer (PSS)	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0
Subject to Future Enforcement	BAL-003-1	No		Frequency Response and Frequency Bias Setting	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	CIP-002-5.1	No		Cyber Security — BES Cyber System Categorization	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	CIP-003-5	No		Cyber Security — Security Management Controls	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	CIP-004-5.1	No		Cyber Security — Personnel & Training	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	CIP-005-5	No		Cyber Security — Electronic Security Perimeter(s)	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	CIP-006-5	No		Cyber Security — Physical Security of BES Cyber Systems	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	CIP-007-5	No		Cyber Security — System Security Management	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	CIP-008-5	No		Cyber Security — Incident Reporting and Response Planning	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	CIP-009-5	No		Cyber Security — Recovery Plans for BES Cyber Systems	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	CIP-010-1	No		Cyber Security — Configuration Change Management and Vulnerability Assessments	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	CIP-011-1	No		Cyber Security — Information Protection	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	CIP-014-1	No		Physical Security	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	EOP-010-1	No		Geomagnetic Disturbance Operations	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	FAC-001-2	No		Facility Interconnection Requirements	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	FAC-002-2	No		Facility Interconnection Studies	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	MOD-025-2	Yes		Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	MOD-032-1	Yes		Data for Power System Modeling and Analysis	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	MOD-033-1	No		Steady-State and Dynamic System Model Validation	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	NUC-001-3	No		Nuclear Plant Interface Coordination	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	PER-005-2	No		Operations Personnel Training	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	PRC-005-2	Yes		Protection System Maintenance	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	PRC-006-NPCC-1	Yes	R	Automatic Underfrequency Load Shedding	0	1	0	0	1	1	0	1	0	1	0	0	0	1	0	0
Subject to Future Enforcement	PRC-019-1	Yes		Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	PRC-024-1	Yes		Generator Frequency and Voltage Protective Relay Settings	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Subject to Future Enforcement	TPL-001-4	No		Transmission System Planning Performance Requirements	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0
Pending Regulatory Approval	BAL-001-2	No		Real Power Balancing Control Performance	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	BAL-002-1a	No		Disturbance Control Performance	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	COM-001-2	No		Communications	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	COM-002-4	No		Operating Personnel Communications Protocols	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	MOD-001-2	No		Available Transmission System Capability	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	MOD-011-0	No		Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	MOD-013-1	No		Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	MOD-014-0	No		Development of Steady-State System Models	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0

Pending Regulatory Approval	MOD-015-0	No		Development of Dynamics System Models	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	MOD-031-1	No		Demand and Energy Data	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	PRC-002-1	No		Define Regional Disturbance Monitoring and Reporting Requirements	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	PRC-003-1	No		Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	PRC-004-3	Yes		Protection System Misoperation Identification and Correction	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	PRC-005-3	Yes		Protection System and Automatic Reclosing Maintenance	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	PRC-012-0	No		Special Protection System Review Procedure	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	PRC-013-0	No		Special Protection System Database	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	PRC-014-0	No		Special Protection System Assessment	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	PRC-020-1	No		Under-Voltage Load Shedding Program Database	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	TOP-006-3	Yes		Monitoring System Conditions	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	TPL-001-3	No		System Performance Under Normal (No Contingency) Conditions (Category A)	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	TPL-002-2b	No		System Performance Following Loss of a Single Bulk Electric System Element (Category B)	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	TPL-003-2a	No		System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	TPL-004-2	No		System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Approval	TPL-005-0	No		Regional and Interregional Self-Assessment Reliability Reports	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Pending Regulatory Filing	CIP-002-3b	No		Cyber Security — Critical Cyber Asset Identification	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Pending Regulatory Filing	CIP-003-3a	No		Cyber Security — Security Management Controls	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Pending Regulatory Filing	CIP-007-3b	No		Cyber Security — Systems Security Management	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Pending Regulatory Filing	COM-002-2a	No		Communications and Coordination	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Pending Regulatory Filing	IRO-001-4	No			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Pending Regulatory Filing	IRO-002-4	No			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Pending Regulatory Filing	IRO-008-2	No			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Pending Regulatory Filing	IRO-010-2	No			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Pending Regulatory Filing	IRO-014-3	No			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Pending Regulatory Filing	IRO-017-1				0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Pending Regulatory Filing	TOP-002-4	Yes			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Pending Regulatory Filing	TOP-003-3	Yes			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0
*See Project 2014-03	IRO-001-3	Yes		Reliability Coordination – Responsibilities and Authorities	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
*See Project 2014-03	IRO-002-3	No		Reliability Coordination — Analysis Tools	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
*See Project 2014-03	IRO-005-4	Yes		Reliability Coordination — Current Day Operations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
*See Project 2014-03	IRO-014-2	No		Coordination Among Reliability Coordinators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
*See Project 2014-03	PRC-001-2	Yes		System Protection Coordination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
*See Project 2014-03	TOP-001-2	Yes		Transmission Operations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
*See Project 2014-03	TOP-002-3	Yes		Operations Planning	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
*See Project 2014-03	TOP-003-2	Yes		Operational Reliability Data	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Designated for Retirement	MOD-024-1	No		Verification of Generator Gross and Net Real Power Capability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Designated for Retirement	MOD-025-1	No		Verification of Generator Gross and Net Reactive Power Capability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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Note: Verify/complete yellow cells. Ensure rest aligns with the paper. Delete rows not needed.

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1	0	1	0	0	0	0	0	1
1	0	1	0	0	0	0	0	1
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1	0	1	0	0	0	0	0	1
1	0	1	0	0	0	0	0	1
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Priority	Status	Standard			Reg	Title	ste	reg	te no re	ste reg	stfe	reg	te no re	sfte reg	pra
High	Subject to Enforcement	PRC-004-2.1a	Applicability Section	Misoperations affecting >75MVA		Analysis and Mitigation of Transmission and Generation Protection System Misoperations	1	0	1	0	0	0	0	0	0
High	Pending Regulatory Approval	PRC-004-3	Applicability Section	Misoperations affecting >75MVA		Protection System Misoperation Identification and Correction	0	0	0	0	0	0	0	0	1
High	Subject to Enforcement	PRC-005-1.1b	Guidance	Point where aggregates to >75MVA		Transmission and Generation Protection System Maintenance and Testing	1	0	1	0	0	0	0	0	0
High	Subject to Future Enforcement	PRC-005-2	Applicability Section	Point where aggregates to >75MVA		Protection System Maintenance	0	0	0	0	1	0	1	0	0
High	Pending Regulatory Approval	PRC-005-3	Applicability Section	Point where aggregates to >75MVA		Protection System and Automatic Reclosing Maintenance	0	0	0	0	0	0	0	0	1
High	Subject to Enforcement	VAR-002-3	Applicability Section& Footnote	Aggregate Facility Level for Voltage Control; Transmission voltage GSUs		Generator Operation for Maintaining Network Voltage Schedules	1	0	1	0	0	0	0	0	0
Medium	Subject to Enforcement	EOP-004-2	No Action	NA		Event Reporting	1	0	1	0	0	0	0	0	0
Medium	Subject to Enforcement	FAC-008-3	Guidance	Individual BES Resources /Elements to Include Aggregating Equipment		Facility Ratings	1	0	1	0	0	0	0	0	0
Medium	Pending Regulatory Filing	IRO-017-1	TBD	TBD			0	0	0	0	0	0	0	0	0
Medium	Subject to Future Enforcement	MOD-025-2	No Action	NA		Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	0	0	0	0	1	0	1	0	0
Medium	Subject to Enforcement	MOD-026-1	No Action	NA		Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions	1	0	1	0	0	0	0	0	0
Medium	Subject to Enforcement	MOD-027-1	No Action	NA		Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	1	0	1	0	0	0	0	0	0
Medium	Subject to Future Enforcement	MOD-032-1	No Action	NA		Data for Power System Modeling and Analysis	0	0	0	0	1	0	1	0	0
Medium	Subject to Enforcement	PRC-001-1.1	Applicability Section	Aggregate Facility Level		System Protection Coordination	1	0	1	0	0	0	0	0	0
Medium	Subject to Future Enforcement	PRC-019-1	Applicability Section	Individual BES Resources/Elements		Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	0	0	0	0	1	0	1	0	0
Medium	Subject to Future Enforcement	PRC-024-1	By Requirement	Individual BES Resources /Elements to Include Aggregating Equipment		Generator Frequency and Voltage Protective Relay Settings	0	0	0	0	1	0	1	0	0
Medium	Subject to Enforcement	PRC-025-1	Guidance	Individual BES Resources /Elements to Include Aggregating Equipment		Generator Relay Loadability	1	0	1	0	0	0	0	0	0
Medium	Subject to Enforcement	TOP-001-1a	No Action	NA		Reliability Responsibilities and Authorities	1	0	1	0	0	0	0	0	0
Medium	Subject to Enforcement	TOP-002-2.1b	Applicability Section	Aggregate Facility Level		Normal Operations Planning	1	0	1	0	0	0	0	0	0
Medium	Pending Regulatory Filing	TOP-002-4	TBD	TBD			0	0	0	0	0	0	0	0	0
Medium	Subject to Enforcement	TOP-003-1	By Requirement	Aggregate Facility Level		Planned Outage Coordination	1	0	1	0	0	0	0	0	0
Medium	Pending Regulatory Filing	TOP-003-3	TBD	TBD			0	0	0	0	0	0	0	0	0
Medium	Subject to Enforcement	TOP-006-2	No Action	NA		Monitoring System Conditions	1	0	1	0	0	0	0	0	0
Medium	Pending Regulatory Approval	TOP-006-3	TBD	TBD		Monitoring System Conditions	0	0	0	0	0	0	0	0	1
Low	Subject to Enforcement	BAL-001-TRE-1	Applicability Section	Aggregate Facility Level	R	Primary Frequency Response in the ERCOT Region	1	1	0	1	0	1	0	0	0
Low	Subject to Enforcement	PRC-004-WECC-1	Applicability Section	Point where aggregates to >75MVA	R	Protection System and Remedial Action Scheme Misoperation	1	1	0	1	0	1	0	0	0
Low	Subject to Future Enforcement	PRC-006-NPCC-1	By Requirement	Individual BES Resources/Elements	R	Automatic Underfrequency Load Shedding	0	1	0	0	1	1	0	1	0
Low	Subject to Enforcement	PRC-006-SERC-01	By Requirement	Individual BES Resources/Elements	R	Automatic Underfrequency Load Shedding Requirements	1	1	0	1	0	1	0	0	0
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Note: Verify/complete yellow cells.
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e values populate the summary table.

Standard Number	Status	Further Review by SDT	Regional
BAL-001-1	Subject to Enforcement	No	No
BAL-001-TRE-1	Subject to Enforcement	Yes	Yes
BAL-002-1	Subject to Enforcement	No	No
BAL-002-WECC-2	Subject to Enforcement	No	Yes
BAL-003-0.1b	Subject to Enforcement	No	No
BAL-004-0	Subject to Enforcement	No	No
BAL-004-WECC-02	Subject to Enforcement	No	Yes
BAL-005-0.2b	Subject to Enforcement	No	No
BAL-006-2	Subject to Enforcement	No	No
BAL-502-RFC-02	Subject to Enforcement	No	Yes
CIP-002-3	Subject to Enforcement	No	No
CIP-003-3	Subject to Enforcement	No	No
CIP-004-3a	Subject to Enforcement	No	No
CIP-005-3a	Subject to Enforcement	No	No
CIP-006-3c	Subject to Enforcement	No	No
CIP-007-3a	Subject to Enforcement	No	No
CIP-008-3	Subject to Enforcement	No	No
CIP-009-3	Subject to Enforcement	No	No
COM-001-1.1	Subject to Enforcement	No	No
COM-002-2	Subject to Enforcement	No	No
EOP-001-2.1b	Subject to Enforcement	No	No
EOP-002-3.1	Subject to Enforcement	No	No
EOP-003-2	Subject to Enforcement	No	No
EOP-004-2	Subject to Enforcement	Yes	No
EOP-005-2	Subject to Enforcement	No	No
EOP-006-2	Subject to Enforcement	No	No
EOP-008-1	Subject to Enforcement	No	No
FAC-001-1	Subject to Enforcement	No	No
FAC-002-1	Subject to Enforcement	No	No
FAC-003-3	Subject to Enforcement	No	No
FAC-008-3	Subject to Enforcement	Yes	No
FAC-010-2.1	Subject to Enforcement	No	No
FAC-011-2	Subject to Enforcement	No	No
FAC-013-2	Subject to Enforcement	No	No
FAC-014-2	Subject to Enforcement	No	No
FAC-501-WECC-1	Subject to Enforcement	No	Yes
INT-004-3	Subject to Enforcement	No	No
INT-006-4	Subject to Enforcement	No	No
INT-009-2	Subject to Enforcement	No	No
INT-010-2	Subject to Enforcement	No	No
INT-011-1	Subject to Enforcement	No	No
IRO-001-1.1	Subject to Enforcement	No	No
IRO-002-2	Subject to Enforcement	No	No
IRO-003-2	Subject to Enforcement	No	No
IRO-004-2	Subject to Enforcement	No	No
IRO-005-3.1a	Subject to Enforcement	No	No
IRO-006-5	Subject to Enforcement	No	No
IRO-006-EAST-1	Subject to Enforcement	No	Yes
IRO-006-TRE-1	Subject to Enforcement	No	Yes
IRO-006-WECC-2	Subject to Enforcement	No	Yes
IRO-008-1	Subject to Enforcement	No	No
IRO-009-1	Subject to Enforcement	No	No
IRO-010-1a	Subject to Enforcement	No	No
IRO-014-1	Subject to Enforcement	No	No

Note: Make sure "Appendix A Source" is correct. This table will auto-populate.

Zeroes indicate missing value on "Appendix A Source".

IRO-015-1	Subject to Enforcement	No	No
IRO-016-1	Subject to Enforcement	No	No
MOD-001-1a	Subject to Enforcement	No	No
MOD-004-1	Subject to Enforcement	No	No
MOD-008-1	Subject to Enforcement	No	No
MOD-010-0	Subject to Enforcement	No	No
MOD-012-0	Subject to Enforcement	No	No
MOD-016-1.1	Subject to Enforcement	No	No
MOD-017-0.1	Subject to Enforcement	No	No
MOD-018-0	Subject to Enforcement	No	No
MOD-019-0.1	Subject to Enforcement	No	No
MOD-020-0	Subject to Enforcement	No	No
MOD-021-1	Subject to Enforcement	No	No
MOD-026-1	Subject to Enforcement	Yes	No
MOD-027-1	Subject to Enforcement	Yes	No
MOD-028-2	Subject to Enforcement	No	No
MOD-029-1a	Subject to Enforcement	No	No
MOD-030-2	Subject to Enforcement	No	No
NUC-001-2.1	Subject to Enforcement	No	No
PER-001-0.2	Subject to Enforcement	No	No
PER-003-1	Subject to Enforcement	No	No
PER-004-2	Subject to Enforcement	No	No
PER-005-1	Subject to Enforcement	No	No
PRC-001-1.1	Subject to Enforcement	Yes	No
PRC-002-NPCC-01	Subject to Enforcement	No	Yes
PRC-004-2.1a	Subject to Enforcement	Yes	No
PRC-004-WECC-1	Subject to Enforcement	Yes	Yes
PRC-005-1.1b	Subject to Enforcement	Yes	No
PRC-006-1	Subject to Enforcement	No	No
PRC-006-SERC-01	Subject to Enforcement	Yes	Yes
PRC-008-0	Subject to Enforcement	No	No
PRC-010-0	Subject to Enforcement	No	No
PRC-011-0	Subject to Enforcement	No	No
PRC-015-0	Subject to Enforcement	No	No
PRC-016-0.1	Subject to Enforcement	No	No
PRC-017-0	Subject to Enforcement	No	No
PRC-018-1	Subject to Enforcement	No	No
PRC-021-1	Subject to Enforcement	No	No
PRC-022-1	Subject to Enforcement	No	No
PRC-023-3	Subject to Enforcement	No	No
PRC-025-1	Subject to Enforcement	Yes	No
TOP-001-1a	Subject to Enforcement	Yes	No
TOP-002-2.1b	Subject to Enforcement	Yes	No
TOP-003-1	Subject to Enforcement	Yes	No
TOP-004-2	Subject to Enforcement	No	No
TOP-005-2a	Subject to Enforcement	No	No
TOP-006-2	Subject to Enforcement	Yes	No
TOP-007-0	Subject to Enforcement	No	No
TOP-007-WECC-1a	Subject to Enforcement	No	Yes
TOP-008-1	Subject to Enforcement	No	No
TPL-001-0.1	Subject to Enforcement	No	No
TPL-002-0b	Subject to Enforcement	No	No
TPL-003-0b	Subject to Enforcement	No	No
TPL-004-0a	Subject to Enforcement	No	No
VAR-001-4	Subject to Enforcement	No	No

VAR-002-3	Subject to Enforcement	Yes	No
VAR-002-WECC-1	Subject to Enforcement	No	Yes
VAR-501-WECC-1	Subject to Enforcement	No	Yes
BAL-003-1	Subject to Future Enforcement	No	No
CIP-002-5.1	Subject to Future Enforcement	No	No
CIP-003-5	Subject to Future Enforcement	No	No
CIP-004-5.1	Subject to Future Enforcement	No	No
CIP-005-5	Subject to Future Enforcement	No	No
CIP-006-5	Subject to Future Enforcement	No	No
CIP-007-5	Subject to Future Enforcement	No	No
CIP-008-5	Subject to Future Enforcement	No	No
CIP-009-5	Subject to Future Enforcement	No	No
CIP-010-1	Subject to Future Enforcement	No	No
CIP-011-1	Subject to Future Enforcement	No	No
CIP-014-1	Subject to Future Enforcement	No	No
EOP-010-1	Subject to Future Enforcement	No	No
FAC-001-2	Subject to Future Enforcement	No	No
FAC-002-2	Subject to Future Enforcement	No	No
MOD-025-2	Subject to Future Enforcement	Yes	No
MOD-032-1	Subject to Future Enforcement	Yes	No
MOD-033-1	Subject to Future Enforcement	No	No
NUC-001-3	Subject to Future Enforcement	No	No
PER-005-2	Subject to Future Enforcement	No	No
PRC-005-2	Subject to Future Enforcement	Yes	No
PRC-006-NPCC-1	Subject to Future Enforcement	Yes	Yes
PRC-019-1	Subject to Future Enforcement	Yes	No
PRC-024-1	Subject to Future Enforcement	Yes	No
TPL-001-4	Subject to Future Enforcement	No	No
BAL-001-2	Pending Regulatory Approval	No	No
BAL-002-1a	Pending Regulatory Approval	No	No
COM-001-2	Pending Regulatory Approval	No	No
COM-002-4	Pending Regulatory Approval	No	No
MOD-001-2	Pending Regulatory Approval	No	No
MOD-011-0	Pending Regulatory Approval	No	No
MOD-013-1	Pending Regulatory Approval	No	No
MOD-014-0	Pending Regulatory Approval	No	No
MOD-015-0	Pending Regulatory Approval	No	No
MOD-031-1	Pending Regulatory Approval	No	No
PRC-002-1	Pending Regulatory Approval	No	No
PRC-003-1	Pending Regulatory Approval	No	No
PRC-004-3	Pending Regulatory Approval	Yes	No
PRC-005-3	Pending Regulatory Approval	Yes	No
PRC-012-0	Pending Regulatory Approval	No	No
PRC-013-0	Pending Regulatory Approval	No	No
PRC-014-0	Pending Regulatory Approval	No	No
PRC-020-1	Pending Regulatory Approval	No	No
TOP-006-3	Pending Regulatory Approval	Yes	No
TPL-001-3	Pending Regulatory Approval	No	No
TPL-002-2b	Pending Regulatory Approval	No	No
TPL-003-2a	Pending Regulatory Approval	No	No
TPL-004-2	Pending Regulatory Approval	No	No
TPL-005-0	Pending Regulatory Approval	No	No
CIP-002-3b	Pending Regulatory Filing	No	No
CIP-003-3a	Pending Regulatory Filing	No	No

CIP-007-3b	Pending Regulatory Filing	No	No
COM-002-2a	Pending Regulatory Filing	No	No
IRO-001-4	Pending Regulatory Filing	No	No
IRO-002-4	Pending Regulatory Filing	No	No
IRO-008-2	Pending Regulatory Filing	No	No
IRO-010-2	Pending Regulatory Filing	No	No
IRO-014-3	Pending Regulatory Filing	No	No
IRO-017-1	Pending Regulatory Filing	0	No
TOP-002-4	Pending Regulatory Filing	Yes	No
TOP-003-3	Pending Regulatory Filing	Yes	No
IRO-001-3	*See Project 2014-03	Yes	No
IRO-002-3	*See Project 2014-03	No	No
IRO-005-4	*See Project 2014-03	Yes	No
IRO-014-2	*See Project 2014-03	No	No
PRC-001-2	*See Project 2014-03	Yes	No
TOP-001-2	*See Project 2014-03	Yes	No
TOP-002-3	*See Project 2014-03	Yes	No
TOP-003-2	*See Project 2014-03	Yes	No
MOD-024-1	Designated for Retirement	No	No
MOD-025-1	Designated for Retirement	No	No
0	0	0	No
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Status	Number of Standards	Number of Standards to be Addressed (Standard, RSAW, Guidance or Further Review)
NERC Standards	**168**	**24**
Subject to Enforcement	98	13
Subject to Future Enforcement	24	5
Pending Regulatory Approval	24	3
Pending Regulatory Filing	12	3
Designated for Retirement	2	0
Proposed for Remand	8	0
Region-specific Standards (*Out of Scope)	**15**	**4**
Subject to Enforcement	14	3
Subject to Future Enforcement	1	1
Pending Regulatory Approval	0	0
Grand Total	**183**	**28**

Note: Make sure "Appendix A Source" is complete. This table will auto-populate.

Priority	Standard Number	Area To Change	Target Applicability
High	PRC-004-2.1a	Applicability Section	Misoperations affecting >75MVA
High	PRC-004-3	Applicability Section	Misoperations affecting >75MVA
High	PRC-005-1.1b	Guidance	Point where aggregates to >75MVA
High	PRC-005-2	Applicability Section	Point where aggregates to >75MVA
High	PRC-005-3	Applicability Section	Point where aggregates to >75MVA
High	VAR-002-3	Applicability Section& Footnote	Aggregate Facility Level for Voltage Control; Transmission voltage GSUs
Medium	EOP-004-2	No Action	NA
Medium	FAC-008-3	Guidance	Individual BES Resources /Elements to Include Aggregating Equipment
Medium	IRO-017-1	TBD	TBD
Medium	MOD-025-2	No Action	NA
Medium	MOD-026-1	No Action	NA
Medium	MOD-027-1	No Action	NA
Medium	MOD-032-1	No Action	NA
Medium	PRC-001-1.1	Applicability Section	Aggregate Facility Level
Medium	PRC-019-1	Applicability Section	Individual BES Resources/Elements
Medium	PRC-024-1	By Requirement	Individual BES Resources /Elements to Include Aggregating Equipment
Medium	PRC-025-1	Guidance	Individual BES Resources /Elements to Include Aggregating Equipment
Medium	TOP-001-1a	No Action	NA
Medium	TOP-002-2.1b	Applicability Section	Aggregate Facility Level
Medium	TOP-002-4	TBD	TBD
Medium	TOP-003-1	By Requirement	Aggregate Facility Level
Medium	TOP-003-3	TBD	TBD
Medium	TOP-006-2	No Action	NA
Medium	TOP-006-3	TBD	TBD
Low	BAL-001-TRE-1	Applicability Section	Aggregate Facility Level
Low	PRC-004-WECC-1	Applicability Section	Point where aggregates to >75MVA
Low	PRC-006-NPCC-1	By Requirement	Individual BES Resources/Elements
Low	PRC-006-SERC-01	By Requirement	Individual BES Resources/Elements
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Note: Make sure "Appendix B Source" is correct. This table will auto-populate.

Zeroes indicate missing value on "Appendix B Source".

Status	Standard	FURTHER REVIEW	REG	Title	ste	reg	ste no reg	ste reg	stfe	reg	sfte no reg	sfte reg	pra	reg	pra no reg	pra reg	prf	reg	prf no reg	prf reg	rem	reg	rem no reg	rem reg	ret	reg	ret no reg	ret reg	total
Subject to Enforcement	BAL-001-1	No		Real Power Balancing Control Performance	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	BAL-001-TRE-1	Yes	R	Primary Frequency Response in the ERCOT Region	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	BAL-002-1	No		Disturbance Control Performance	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	BAL-002-WECC-2	No	R	Contingency Reserve	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	BAL-003-0.1b	No		Frequency Response and Bias	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	BAL-004-0	No		Time Error Correction	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	BAL-004-WECC-02	No	R	Automatic Time Error Correction (ATEC)	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	BAL-005-0.2b	No		Automatic Generation Control	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	BAL-006-2	No		Inadvertent Interchange	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	BAL-502-RFC-02	No	R	Planning Resource Adequacy Analysis, Assessment and Documentation	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	CIP-002-3	No		Cyber Security — Critical Cyber Asset Identification	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	CIP-003-3	No		Cyber Security — Security Management Controls	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	CIP-004-3a	No		Cyber Security — Personnel & Training	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	CIP-005-3a	No		Cyber Security — Electronic Security Perimeter(s)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	CIP-006-3c	No		Cyber Security — Physical Security of Critical Cyber Assets	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	CIP-007-3a	No		Cyber Security — Systems Security Management	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	CIP-008-3	No		Cyber Security — Incident Reporting and Response Planning	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	CIP-009-3	No		Cyber Security — Recovery Plans for Critical Cyber Assets	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	COM-001-1.1	No		Telecommunications	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	COM-002-2	No		Communications and Coordination	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	EOP-001-2.1b	No		Emergency Operations Planning	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	EOP-002-3.1	No		Capacity and Energy Emergencies	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	EOP-003-2	No		Load Shedding Plans	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	EOP-004-2	Yes		Event Reporting	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	EOP-005-2	No		System Restoration from Blackstart Resources	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	EOP-006-2	No		System Restoration Coordination	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	EOP-008-1	No		Loss of Control Center Functionality	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	FAC-001-1	No		Facility Connection Requirements	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	FAC-002-1	No		Coordination of Plans For New Generation, Transmission, and End-User Facilities	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	FAC-003-3	No		Transmission Vegetation Management	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	FAC-008-3	Yes		Facility Ratings	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	FAC-010-2.1	No		System Operating Limits Methodology for the Planning Horizon	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	FAC-011-2	No		System Operating Limits Methodology for the Operations Horizon	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	FAC-013-2	No		Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	FAC-014-2	No		Establish and Communicate System Operating Limits	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	FAC-501-WECC-1	No	R	Transmission Maintenance	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	INT-004-3	No		Dynamic Transfers	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	INT-006-4	No		Evaluation of Interchange Transactions	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	INT-009-2	No		Implementation of Interchange	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	INT-010-2	No		Interchange Initiation and Modification for Reliability	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	INT-011-1	No		Intra-Balancing Authority Transaction Identification	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-001-1.1	No		Reliability Coordination — Responsibilities and Authorities	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-002-2	No		Reliability Coordination — Facilities	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-003-2	No		Reliability Coordination — Wide-Area View	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-004-2	No		Reliability Coordination — Operations Planning	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-005-3.1a	No		Reliability Coordination — Current Day Operations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-006-5	No		Reliability Coordination — Transmission Loading Relief (TLR)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-006-EAST-1	No	R	Transmission Loading Relief Procedure for the Eastern Interconnection	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	IRO-006-TRE-1	No	R	IROL and SOL Mitigation in the ERCOT Region	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	IRO-006-WECC-2	No	R	Qualified Transfer Path Unscheduled Flow (USF) Relief	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	IRO-008-1	No		Reliability Coordinator Operational Analyses and Real-time Assessments	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-009-1	No		Reliability Coordinator Actions to Operate Within IROLs	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-010-1a	No		Reliability Coordinator Data Specification and Collection	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-014-1	No		Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-015-1	No		Notifications and Information Exchange Between Reliability Coordinators	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	IRO-016-1	No		Coordination of Real-time Activities Between Reliability Coordinators	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-001-1a	No		Available Transmission System Capability	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-004-1	No		Capacity Benefit Margin	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-008-1	No		Transmission Reliability Margin Calculation Methodology	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-010-0	No		Steady-State Data for Modeling and Simulation of the Interconnected Transmission System	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-012-0	No		Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-016-1.1	No		Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-017-0.1	No		Aggregated Actual and Forecast Demands and Net Energy for Load	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-018-0	No		Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-019-0.1	No		Reporting of Interruptible Demands and Direct Control Load Management	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-020-0	No		Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1

Subject to Enforcement	MOD-021-1	No		Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-026-1	Yes		Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-027-1	Yes		Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-028-2	No		Area Interchange Methodology	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-029-1a	No		Rated System Path Methodology	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	MOD-030-2	No		Flowgate Methodology	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	NUC-001-2.1	No		Nuclear Plant Interface Coordination	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PER-001-0.2	No		Operating Personnel Responsibility and Authority	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PER-003-1	No		Operating Personnel Credentials	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PER-004-2	No		Reliability Coordination — Staffing	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PER-005-1	No		System Personnel Training	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-001-1.1	Yes		System Protection Coordination	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-002-NPCC-01	No	R	Disturbance Monitoring	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	PRC-004-2.1a	Yes		Analysis and Mitigation of Transmission and Generation Protection System Misoperations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-004-WECC-1	Yes	R	Protection System and Remedial Action Scheme Misoperation	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	PRC-005-1.1b	Yes		Transmission and Generation Protection System Maintenance and Testing	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-006-1	No		Automatic Underfrequency Load Shedding	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-006-SERC-01	Yes	R	Automatic Underfrequency Load Shedding Requirements	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	PRC-008-0	No		Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-010-0	No		Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-011-0	No		Undervoltage Load Shedding System Maintenance and Testing	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-015-0	No		Special Protection System Data and Documentation	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-016-0.1	No		Special Protection System Misoperations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-017-0	No		Special Protection System Maintenance and Testing	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-018-1	No		Disturbance Monitoring Equipment Installation and Data Reporting	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-021-1	No		Under-Voltage Load Shedding Program Data	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-022-1	No		Under-Voltage Load Shedding Program Performance	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-023-3	No		Transmission Relay Loadability	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	PRC-025-1	Yes		Generator Relay Loadability	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TOP-001-1a	Yes		Reliability Responsibilities and Authorities	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TOP-002-2.1b	Yes		Normal Operations Planning	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TOP-003-1	Yes		Planned Outage Coordination	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TOP-004-2	No		Transmission Operations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TOP-005-2a	No		Operational Reliability Information	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TOP-006-2	Yes		Monitoring System Conditions	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TOP-007-0	No		Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TOP-007-WECC-1a	No	R	System Operating Limits	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	TOP-008-1	No		Response to Transmission Limit Violations	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TPL-001-0.1	No		System Performance Under Normal (No Contingency) Conditions (Category A)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TPL-002-0b	No		System Performance Following Loss of a Single Bulk Electric System Element (Category B)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TPL-003-0b	No		System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	TPL-004-0a	No		System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	VAR-001-4	No		Voltage and Reactive Control	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	VAR-002-3	Yes		Generator Operation for Maintaining Network Voltage Schedules	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Enforcement	VAR-002-WECC-1	No	R	Automatic Voltage Regulators (AVR)	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Enforcement	VAR-501-WECC-1	No	R	Power System Stabilizer (PSS)	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Future Enforcement	BAL-003-1	No		Frequency Response and Frequency Bias Setting	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	CIP-002-5.1	No		Cyber Security — BES Cyber System Categorization	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	CIP-003-5	No		Cyber Security — Security Management Controls	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	CIP-004-5.1	No		Cyber Security — Personnel & Training	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	CIP-005-5	No		Cyber Security — Electronic Security Perimeter(s)	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	CIP-006-5	No		Cyber Security — Physical Security of BES Cyber Systems	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	CIP-007-5	No		Cyber Security — System Security Management	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	CIP-008-5	No		Cyber Security — Incident Reporting and Response Planning	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	CIP-009-5	No		Cyber Security — Recovery Plans for BES Cyber Systems	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	CIP-010-1	No		Cyber Security — Configuration Change Management and Vulnerability Assessments	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	CIP-011-1	No		Cyber Security — Information Protection	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	CIP-014-1	No		Physical Security	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	EOP-010-1	No		Geomagnetic Disturbance Operations	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	FAC-001-2	No		Facility Interconnection Requirements	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	FAC-002-2	No		Facility Interconnection Studies	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	MOD-025-2	Yes		Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	MOD-032-1	Yes		Data for Power System Modeling and Analysis	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	MOD-033-1	No		Steady-State and Dynamic System Model Validation	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	NUC-001-3	No		Nuclear Plant Interface Coordination	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	PER-005-2	No		Operations Personnel Training	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	PRC-005-2	Yes		Protection System Maintenance	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	PRC-006-NPCC-1	Yes	R	Automatic Underfrequency Load Shedding	0	1	0	0	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Subject to Future Enforcement	PRC-019-1	Yes		Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1

Subject to Future Enforcement	PRC-024-1	Yes		Generator Frequency and Voltage Protective Relay Settings	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Subject to Future Enforcement	TPL-001-4	No		Transmission System Planning Performance Requirements	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	BAL-001-2	No		Real Power Balancing Control Performance	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	BAL-002-1a	No		Disturbance Control Performance	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	COM-001-2	No		Communications	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	COM-002-4	No		Operating Personnel Communications Protocols	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	MOD-001-2	No		Available Transmission System Capability	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	MOD-011-0	No		Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	MOD-013-1	No		Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	MOD-014-0	No		Development of Steady-State System Models	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	MOD-015-0	No		Development of Dynamics System Models	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	MOD-031-1	No		Demand and Energy Data	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	PRC-002-1	No		Define Regional Disturbance Monitoring and Reporting Requirements	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	PRC-003-1	No		Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	PRC-004-3	Yes		Protection System Misoperation Identification and Correction	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	PRC-005-3	Yes		Protection System and Automatic Reclosing Maintenance	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	PRC-012-0	No		Special Protection System Review Procedure	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	PRC-013-0	No		Special Protection System Database	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	PRC-014-0	No		Special Protection System Assessment	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	PRC-020-1	No		Under-Voltage Load Shedding Program Database	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	TOP-006-3	Yes		Monitoring System Conditions	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	TPL-001-3	No		System Performance Under Normal (No Contingency) Conditions (Category A)	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	TPL-002-2b	No		System Performance Following Loss of a Single Bulk Electric System Element (Category B)	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	TPL-003-2a	No		System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	TPL-004-2	No		System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Approval	TPL-005-0	No		Regional and Interregional Self-Assessment Reliability Reports	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	CIP-002-3b	No		Cyber Security — Critical Cyber Asset Identification	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	CIP-003-3a	No		Cyber Security — Security Management Controls	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	CIP-007-3b	No		Cyber Security — Systems Security Management	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	COM-002-2a	No		Communications and Coordination	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	IRO-001-4	No			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	IRO-002-4	No			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	IRO-008-2	No			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	IRO-010-2	No			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	IRO-014-3	No			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	IRO-017-1				0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	TOP-002-4	Yes			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
Pending Regulatory Filing	TOP-003-3	Yes			0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
*See Project 2014-03	IRO-001-3	Yes		Reliability Coordination – Responsibilities and Authorities	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	1
*See Project 2014-03	IRO-002-3	No		Reliability Coordination — Analysis Tools	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	1
*See Project 2014-03	IRO-005-4	Yes		Reliability Coordination — Current Day Operations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	1
*See Project 2014-03	IRO-014-2	No		Coordination Among Reliability Coordinators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	1
*See Project 2014-03	PRC-001-2	Yes		System Protection Coordination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	1
*See Project 2014-03	TOP-001-2	Yes		Transmission Operations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	1
*See Project 2014-03	TOP-002-3	Yes		Operations Planning	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	1
*See Project 2014-03	TOP-003-2	Yes		Operational Reliability Data	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	1
Designated for Retirement	MOD-024-1	No		Verification of Generator Gross and Net Real Power Capability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	1
Designated for Retirement	MOD-025-1	No		Verification of Generator Gross and Net Reactive Power Capability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	1
							98	14			24	1			24	0			12	0			8	0			2	0	183

These values populate the summary table.

Note: Verify/complete yellow cells. Ensure rest aligns with the paper. Delete rows not needed.

Priority	Status	Standard			Reg	Title
High	Subject to Enforcement	PRC-004-2.1a	Applicability Section	Misoperations affecting >75MVA		Analysis and Mitigation of Transmission and Generation Protection System Misoperations
High	Pending Regulatory Approval	PRC-004-3	Applicability Section	Misoperations affecting >75MVA		Protection System Misoperation Identification and Correction
High	Subject to Enforcement	PRC-005-1.1b	Guidance	Point where aggregates to >75MVA		Transmission and Generation Protection System Maintenance and Testing
High	Subject to Future Enforcement	PRC-005-2	Applicability Section	Point where aggregates to >75MVA		Protection System Maintenance
High	Pending Regulatory Approval	PRC-005-3	Applicability Section	Point where aggregates to >75MVA		Protection System and Automatic Reclosing Maintenance
High	Subject to Enforcement	VAR-002-3	Applicability Section& Footnote	Aggregate Facility Level for Voltage Control; Transmission voltage GSUs		Generator Operation for Maintaining Network Voltage Schedules
Medium	Subject to Enforcement	EOP-004-2	No Action	NA		Event Reporting
Medium	Subject to Enforcement	FAC-008-3	Guidance	Individual BES Resources /Elements to Include Aggregating Equipment		Facility Ratings
Medium	Pending Regulatory Filing	IRO-017-1	TBD	TBD		
Medium	Subject to Future Enforcement	MOD-025-2	No Action	NA		Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
Medium	Subject to Enforcement	MOD-026-1	No Action	NA		Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions
Medium	Subject to Enforcement	MOD-027-1	No Action	NA		Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
Medium	Subject to Future Enforcement	MOD-032-1	No Action	NA		Data for Power System Modeling and Analysis
Medium	Subject to Enforcement	PRC-001-1.1	Applicability Section	Aggregate Facility Level		System Protection Coordination
Medium	Subject to Future Enforcement	PRC-019-1	Applicability Section	Individual BES Resources/Elements		Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
Medium	Subject to Future Enforcement	PRC-024-1	By Requirement	Individual BES Resources /Elements to Include Aggregating Equipment		Generator Frequency and Voltage Protective Relay Settings
Medium	Subject to Enforcement	PRC-025-1	Guidance	Individual BES Resources /Elements to Include Aggregating Equipment		Generator Relay Loadability
Medium	Subject to Enforcement	TOP-001-1a	No Action	NA		Reliability Responsibilities and Authorities
Medium	Subject to Enforcement	TOP-002-2.1b	Applicability Section	Aggregate Facility Level		Normal Operations Planning
Medium	Pending Regulatory Filing	TOP-002-4	TBD	TBD		
Medium	Subject to Enforcement	TOP-003-1	By Requirement	Aggregate Facility Level		Planned Outage Coordination
Medium	Pending Regulatory Filing	TOP-003-3	TBD	TBD		
Medium	Subject to Enforcement	TOP-006-2	No Action	NA		Monitoring System Conditions
Medium	Pending Regulatory Approval	TOP-006-3	TBD	TBD		Monitoring System Conditions
Low	Subject to Enforcement	BAL-001-TRE-1	Applicability Section	Aggregate Facility Level	R	Primary Frequency Response in the ERCOT Region
Low	Subject to Enforcement	PRC-004-WECC-1	Applicability Section	Point where aggregates to >75MVA	R	Protection System and Remedial Action Scheme Misoperation
Low	Subject to Future Enforcement	PRC-006-NPCC-1	By Requirement	Individual BES Resources/Elements	R	Automatic Underfrequency Load Shedding
Low	Subject to Enforcement	PRC-006-SERC-01	By Requirement	Individual BES Resources/Elements	R	Automatic Underfrequency Load Shedding Requirements

Standard	ste	reg	te no re	ste reg	stfe	reg	te no re	sfte reg	pra	reg	ra no re	pra reg	prf	reg	prf no reg	prf reg	rem	reg	em no re	rem reg	ret	reg	et no re	ret reg	total
PRC-004-2.1a	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
PRC-004-3	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
PRC-005-1.1b	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
PRC-005-2	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
PRC-005-3	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
VAR-002-3	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
EOP-004-2	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
FAC-008-3	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
IRO-017-1	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
MOD-025-2	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
MOD-026-1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
MOD-027-1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
MOD-032-1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
PRC-001-1.1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
PRC-019-1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
PRC-024-1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
PRC-025-1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
TOP-001-1a	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
TOP-002-2.1b	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
TOP-002-4	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
TOP-003-1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
TOP-003-3	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	1
TOP-006-2	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
TOP-006-3	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
BAL-001-TRE-1	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
PRC-004-WECC-1	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
PRC-006-NPCC-1	0	1	0	0	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
PRC-006-SERC-01	1	1	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
			13	3			5	1			3	0			3	0			0	0			0	0	28

Note: Verify/complete yellow cells.
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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the posted documents. The electronic comment form must be completed by **January 20, 2015.**

If you have questions please contact Katherine Street (by email) or by telephone at 404-446-9702.

All documents for this project are available on the project page.

Background Information

This posting solicits informal comments on the Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) standards drafting team (SDT) revised draft White Paper, which provides background and technical rationale for proposed revisions to the applicability of several Reliability Standards. The revised draft White Paper is the second version following the first version posted on April 17, 2014. This version of the White Paper is intended to support the DGR SDT's recommendations on the high-priority DGR standards. The DGR SDT intends to post a third and final version of the White Paper at the conclusion of this project.

As explained in the White Paper, the goal of the DGR SDT is to ensure that Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System (BPS), as the characteristics of operating dispersed power producing resources can be unique. In light of the revised BES definition approved by the Federal Energy Regulatory Authority (FERC) in 2014, the intent of this effort is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources, where the status quo does not create a reliability gap, and to ensure continent-wide consistency in the application of Reliability Standards to dispersed power producing resources.

The DGR SDT performed a review of all standards that apply to GOs and GOPs (listed in Appendix A, as posted) and determined how each standard requirement should be appropriately applied to dispersed power producing resources, which are categorized as follows:

- The existing standard language is appropriate when applied to dispersed power producing resources and does not need to be addressed;

- The existing standard language is appropriate when applied to dispersed power producing resources but additional guidance is needed to clarify either how to implement the requirements for dispersed generating resources or how to demonstrate compliance for such resources; and
- The existing standard language needs to be modified in order to account for the unique characteristics of dispersed power producing resources. This could be accomplished through the Applicability Section of the standard in most cases; or, if required, through changes to the individual requirements. However, please note that any recommended changes to requirements are limited to changes in the applicability of the subject requirement and will <u>not</u> include technical changes to any requirement.

Other standards (listed in posted Appendix B) have been revised or require further review by the SDT to determine the necessity and the type of clarification or guidance to the applicability for dispersed power producing resources.

This posting includes three documents:
- Revised draft White Paper;
- Appendix A – List of all standards reviewed by the DGR SDT; and
- Appendix B – List of standards recommended as requiring further consideration for dispersed power producing resources.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you agree with the accuracy of the technical content of the posted version of the White Paper? If not, please explain and offer alternative language.

   ☐ Yes
   ☐ No

   Comments:

2. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

   ☐ Yes
   ☐ No

   Comments:

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
White Paper

Informal Comment Period Now Open through January 20, 2015

Now Available

An informal comment period for the Project 2014-01 Standards Applicability for Dispersed Generation Resources White Paper is now open through **8 p.m. Eastern on Tuesday, January 20, 2015.**

The white paper is intended to provide technical rationale and justification to support identification of standards that will require modifications to applicability for the unique characteristics of dispersed power producing resources as identified under Inclusion I4 of the BES definition that became effective on July 1, 2014. Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

The drafting team will review stakeholder comments and develop modifications for those standards for which modified applicability for dispersed generation resources is justified and supports reliability. In cases where applicability changes are developed for standards that are being modified in another standard development projects, the applicability changes will be coordinated with the drafting team making the technical changes, but will be balloted separately and filed for regulatory approval in a separate petition.

For information on the Standards Development Process, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street, Standards Developer, or at 404-446-9702.

Individual or group. (14 Responses)
Name (5 Responses)
Organization (5 Responses)
Group Name (9 Responses)
Lead Contact (9 Responses)
Question 1 (14 Responses)
Question 1 Comments (14 Responses)
Question 2 (13 Responses)
Question 2 Comments (14 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Page numbers in the following comments refer to the clean version of the document. On the cover page the title should be revised to read Proposed Revisions to the Applicability of NERC Reliability Standards to Dispersed Generation Resources. In the second paragraph on page 5, it states "…This document provides justification of, and proposes revisions to, the applicability of the Reliability Standards and requirements, both existing and in development, and should be considered guidance for future standard development efforts…" This could result in considerable time savings and effort in the development of standards. Is there a mechanism in place for ensuring this is done? On page 9 above the table it is mentioned that "…In cases where a change is recommended to a regional standard, the SDT will notify the affected region." Is it appropriate for the SDT to make this notification, and when will the notification be made? Bulk Power System is used extensively on page 10, and not capitalized. If it is intended for its definition to be consistent with that listed in the NERC Glossary, it should be capitalized. Also, from the NERC Glossary, it should be Bulk-Power System. In Section 3.3.3 Prioritization Methodology, for high priority could exceptions be issued for entities to avoid the pitfalls of rushing changes to standards? Exceptions should be considered for medium and low priorities as well. In the medium priority bullet "appreciable reliability benefit" is used. What is considered an "appreciable reliability benefit"? There are operating conditions where the loss of 5MW can put the Bulk-Power System in an Emergency condition. On page 22 of 33 in Section 4.10.12 PRC-024— Generator Frequency and Voltage Protective Relay Settings, the second sentence should be reworded to read to be consistent with the language in the Rationale for Footnotes 4 and 6 in PRC-024-2: The SDT has determined it is appropriate to require that Protection System settings applied on both the individual generating units and aggregating equipment (including any Protection Systems applied on non-BES portions of the aggregating equipment), are set respecting the "no-trip zone" referenced in the requirements to maintain reliability of the BES. The Appendix A Source incorrectly lists PRC-002-1 as Pending Regulatory Approval. PRC-002-1 was remanded by FERC, and PRC-002-2 has been submitted to FERC and is Pending Regulatory Approval. This might appear elsewhere in the Appendices, and needs to be reviewed. PRC-002-1 dealt with installation requirements; PRC-002-2 deals with the capturing of data.
Group
MRO-NERC Standards Review Forum
Joe Depoorter
No
Page 7 of 33, last sentence states: "Thus, for some standards discussed in this paper it is appropriate to apply requirements at the plant level rather than the individual generating unit". If the SDT is inferring the "plant level" is the point of aggregation of 75 MVA or at the Facility (?), then please state that or provide a foot note. This term can be interpreted differently by each reader of this section. Section 4.4.4. The NSRF recommends that FAC-008-3 be restricted to only the individual generation resource per the I4 inclusion of the BES definition. FAC-001-1, R3 outlines Facility connection requirements. The TO can request updates of this information per R4. Note that

GO/GOPs are either vertically integrated with their TOP or have a good working rapport with their TOP since working together since 2007. The industry does not need granular Requirements that fall outside the scope of the BES definition i.e., ratings of collector systems. If a TOP wants this information they can always request it outside of a NERC Standard.
Group
DTE Electric Co.
Kathleen Black
No
The discussion under PRC-004 (Section 4.10.4, paragraph 4) concerning setting errors on individual units suggests that this may be applicable even if less than 75 MVA is affected. The statement should be modified to clarify that only misoperations affecting more than 75 MVA are in scope.
No
No additional comments.
Individual
Thomas Foltz
American Electric Power
Yes
In the section for PRC-024, we believe the text "are set within the no-trip zone" is incorrect. Instead, the text should read as follows: "The SDT has determined it is appropriate to require that Protection System settings applied on both the individual generating units and aggregating equipment (including any Protection Systems applied on non-BES portions of the aggregating equipment are set *outside (or in accordance with)* the "no-trip zone" referenced in the requirements to maintain reliability of the BES."
No
Individual
Heather Bowden
EDP Renewables North America LLC
No
FAC-008: Technical guidance for FAC-008 is needed for dispersed power producing resources. For dispersed power producing resources, the Facility ratings should only be necessary for equipment which aggregates generation to 75 MVA or higher. The impact the individual generators have to the BES reliability is negligible. Since the NERC technical justification for applicability as presented in the Bulk Electric System Definition Reference Document dated April 2014 defines BES resources of being 75 MVA or higher, only the equipment that meets this threshold should be included. The applicability criteria for dispersed power producing resources should be consistent across the Reliability Standards.
Yes
Since the NERC technical justification for applicability as presented in the Bulk Electric System Definition Reference Document dated April 2014 defines BES resources of being 75 MVA or higher, only the equipment that meets this threshold should be included. The applicability criteria for dispersed power producing resources should be consistent across the Reliability Standards.
Group
Dominion
Connie Lowe
Yes
Yes
Dominion understands this whitepaper is constantly being updated and suggests the following be updated as the due dates below have past since the SDT redlined the document; Section 10.7 PRC-005-2; in the last sentence change January 22, 2014 to January 22, 2015 and update ballot

comments as this ballot has closed. Section 10.10 PRC-019-1; update results of PRC-10-1 comments/ballot that closed December 22, 2014. Section 10.12 PRC-024; needs to be updated with the PRC-024 posting initial comment/ballot that closed December 22, 2014. Section 4.11.2 TOP-001-3; footnote 25 - update results of TOP-001-3 ballot which closed on January 7, 2015.
Individual
Mike Smith
Manitoba Hydro
Yes
The terms BES and BPS are used inconsistently, making the white paper confusing to read.
No
Individual
Craig Jones
Idaho Power
Yes
No
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
No
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
No
The proposed changes included in FAC-008-3(X) are essentially specifying an unnecessary design review of entire PV and wind plants. This outcome of the proposed inclusion of generating resources identified in BES Definition Inclusion I4 in FAC-008 is not needed and is not necessary. The GO sharing of the ratings and capabilities of generating plant with planning entities is sufficiently and adequately in other existing NERC standards. To be specific, the generating plant MW and MVAR capabilities are required to be verified by MOD-025-2. The ability of a generating plant to remain connected for specified frequency and voltage excursions (and the reporting to the PC or TP any lack of the ability to do so) is required by PRC-024. The soon to be enforceable MOD-032 contains requirements for the GO to provide a plethera of plant specific modeling information (steady-state, dynamic, and short circuit) to the PC or TP including real power capabilities - gross maximum and minimum values; b. reactive power capabilities - maximum and minimum values at real power capabilities in a above; c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand; d. regulated bus* and voltage set point* (as typically provided by the TOP); e. machine MVA base; f. generator step up transformer data (1. nominal voltages of windings, 2. impedance(s), 3. tap ratios (voltage or phase angle)*, 4. minimum and maximum tap position limits, 5. number of tap positions (for both the ULTC and NLTC), 6. regulated bus (for voltage regulating transformers)*, 7. ratings (normal and emergency)*, 8. in-service status*); g. generator type (hydro, wind, fossil, solar, nuclear, etc); h. in-service status* These realizations expose the fact that FAC-008-3 is not needed at all for generating resources. One sentence of the PRC-025 paragraph (page 28 of the 11 Dec 2014 draft) is incomplete: "The SDT has determined it is appropriate to require that Protection System settings applied on both the individual generating units at a dispersed generation power producing resource

site as applicable to this standard." The use of "both" makes it sound as though two independent parts will subsequently named, and they are not. TPL-007-1 contains a GO requirement and should be addressed by the white paper.
Yes
Since some standards (PRC-024) have recently been modified to account for the unique characteristics of dispersed power generating resources using footnotes, this method of modification should be mentioned in the third bullet of page 2 of the red line 11 Dec 2014 draft of the White Paper. This bullet could be revised to read: "The existing standard language needs to be modified in order to account for the unique characteristics of dispersed power producing resources. This could be accomplished through the applicability Applicability section Section of the standard in most cases, through narrowly- tailored changes to the individual requirements, if needed, or through the use of footnotes which clarify the applicability.
Group
Duke Energy
Colby Bellville
Yes
No
Duke Energy would like to thank the drafting team for its efforts in drafting the DGR White Paper.
Group
ACES Standards Collaborators
Jason Marshall
No
(1) The drafting team has done an excellent job reviewing all of the standards that apply to GOs and GOPs and also identifying some of the ancillary issues such as the interaction of BAs, TOPs, and RCs and dispersed generation resources. However, we do believe there are still some issues that have not been fully addressed in the white paper. (2) The white paper should explain why the drafting team modified its view on both MOD-026 and MOD-027. It only says upon further review the drafting team no longer believes the applicability requires further refinement. What specifically in the review changed the drafting team’s mind? This should be explained in the white paper. (3) We disagree that PRC-001-1.1 R2 does not require modifications. While we agree with the SDT’s interpretation that the loss of an individual generating unit at a dispersed generation resource will not have material impact on reliability and therefore the requirement is not applicable, we do not believe all GOPs (and possibly auditors) will interpret the requirement in this manner. GOPs may not have the transmission system knowledge to understand that losing a single generation resource in a dispersed generation site does not have a material impact on reliability. A simple revision or technical explanation in the application guidelines section is warranted to be sure everyone interprets the standard consistent with the drafting team’s explanation in the white paper. (4) The TOP standards section of the white paper needs a wholesale re-evaluation as it appears to be out of sync with the work of the Project 2014-03 TOP and IRO Revisions standards drafting team. This drafting team is wrapping up their work and all standards have either passed the initial/additional ballot or have passed the final ballot and appear to be different than what was evaluated. For instance, TOP-001-3 is much broader than described in the white paper and encompasses much more than ensuring “TOP directives are complied with.” Further, TOP-002-4 and TOP-003-3 were not even evaluated in the white paper. Since the SDT has not identified the existing TOP standards as high priority issues, will the SDT truly recommend changes to them when they will be replaced by the standards from Project 2014-03? (5) The CIP section is confusing and requires additional modification. Based on the inclusion of the low impact requirements or “Elements” as described in the white paper and from Attachment 1 in CIP-003-7, it would appear that there is an assumption that these dispersed generation resources could never be categorized as medium or high impact. We are not sure this will be universally true. However, if the drafting team is making this assumption, please document it explicitly in the white paper. Furthermore, we recommend removing the low impact requirements/”Elements” from the white paper as they are not final and do not provide any additional clarification to the work of this drafting team at this juncture.
No

Thank you for the opportunity to comment.
Group
Arizona Public Service Company
Kristie Cocco
No
FAC-008: SDT recommends additional guidance but intent is not clear. Any of the facility components in a dispersed generation complex should not be subjected to facility rating calculations. There is very little reliability benefit in doing so. The dispersed power generation complex is not subjected to higher loadings than the design value for any realistic scenario.
Yes
TOP-001-3 Requirements R13, R14, R15 should not apply to variable generation even at the aggregate level. It is hard to predict reduction in real and reactive power capability of variable generation units in real time. There is no reliability benefits of these standards as applied to variable generation. TOP needs to be prepared for maximum changes in real and reactive power from these complexes.
Group
SPP Standards Review Group
Robert Rhodes
No
Reference is made to BES reliability in 4.7.3 MOD-024-1, 4.7.4 MOD-025-1 and 4.7.5 MOD-025-2 whereas the reference is to ‘reliability of the BPS’ in 4.6.3 IRO-010. It appears that the drafting team swaps back and forth from one to the other quite often in the document. We should be consistent throughout the whitepaper. We prefer BES reliability. Section 4.11 TOP may need to be revised based on the on-going Project 2014-03 Revisions to TOP and IRO Standards which has extensively revised the TOP standards. TOP-002-4 and TOP-003-3 have been accepted by the industry and adopted by the NERC Board. TOP-001-3 is currently posted for Final Ballot having successfully passed its last additional ballot which closed on January 7, 2015. The 1st sentence in the 1st bullet under 4.11.3.2 Requirement R13 is not very clear. Without knowing exactly what the SDT is trying to say, we offer the following as a possible replacement. ‘Due to the number of individual generators at a dispersed power producing resource, the internal Real Power losses, and the natural inductance and capacitance of dispersed power resource systems connected in series, verification of real and reactive capabilities should be conducted at the dispersed power producing resource aggregate Facility level.’
Yes
The following are primarily typo/grammatical suggestions. In the first line of the Executive Summary the SDT uses White Paper when referring to the document. The Project 2014-03 SDT most recently used whitepaper when referencing its System Operating Limit (SOL) document. NERC needs to be consistent with the use of whitepaper in all documentation across all projects. Also in the first paragraph of the Executive Summary, hyphenate Bulk-Power System as defined in the NERC Glossary of Terms Used in Reliability Standards. Change the ‘and’ at the end of the 2nd bullet in the 2nd paragraph of the Executive Summary to ‘or’. Delete ‘be’ in the next to last line of the 1st paragraph on Page 2 of the Executive Summary. Delete the comma after ‘Standards Committee’ in the 1st line of the 1st paragraph under 3 Background. Capitalize ‘Transmission’ in the 1st line of the 3rd paragraph under 3.2.1 Design Characteristics. Be sure it is capitalized correctly throughout the whitepaper. For example, in the last line of the 2nd paragraph under 3.2.2 Operational Characteristics. Insert ‘the’ between ‘affect’ and ‘GO’ in the 3rd line of the paragraph under 4.1 BAL. Delete the phrase ‘changes to add’ in the next to last line of the 2nd paragraph under 4.4.4 FAC-008 – Facility Ratings. Change the references to MOD-032 in 4.7.1 MOD-010 and 4.7.2 MOD-012 from 5.7.8 to 4.7.8. Replace ‘do’ with ‘does’ in the last line of the paragraph under 4.9 PER. Capitalize ‘Protection Systems’ in the next to last line of the last paragraph under 4.10.1 PRC-001-1.1 – System Protection Coordination. Replace ‘is’ with ‘was’ in the first line of the paragraph under 4.10.2 PRC-001-2 – System Protection Coordination. In the 3rd line of the same paragraph, change ‘This Standard version…’ to ‘This standard version…’. Replace ‘do’ with ‘does’ in the last line of the paragraph under 4.10.3 PRC-002-NPCC-01 – Disturbance Monitoring. As in the previously mentioned comment on 4.9 PER, standards is not the subject of these sentences, applicability is. ‘Does’ is the

proper verb to attain subject/verb agreement. Change the reference to ‘BPS criteria’ in the 2nd line of the 1st paragraph under 4.10.4 PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations to ‘BES criteria’ since the Purpose of PRC-004-2.1a refers to ‘...reliability of the Bulk Electric System (BES)...’. Additional consideration should be given to the references to BPS reliability in this paragraph. (See our comment in Question 1 above.) Make the plural ‘operations’ in the 2nd line of the 4th paragraph under 4.10.4 PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations parenthetical ‘operation(s)’ since it could be singular or plural. Capitalize ‘Misoperation’ in the 3rd line of the 5th paragraph under 4.10.4 PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. Replace ‘benefit’ with ‘benefits’ in the 2nd line of the 1st paragraph under 4.10.7 PRC-005-2 – Protection System Maintenance. Capitalize ‘Transmission’ in the 2nd line of the 3rd paragraph under 4.10.7 PRC-005-2 – Protection System Maintenance. There has apparently been some sort of mix-up between the redline version and the clean version of the whitepaper regarding the last paragraph under 4.10.7 PRC-005-2 – Protection System Maintenance and the beginning of 4.10.8 PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding. Capitalize ‘Transmission Lines’ in the 3rd and 7th lines of the paragraph under 4.10.11 PRC-023 – Transmission Relay Loadability. Capitalize ‘Protection Systems’ in the 10th line of the paragraph under 4.10.12 PRC-024 – Generator Frequency and Voltage Protective Relay Settings. Capitalize ‘Protection Systems’ in the 10th line of the paragraph under 4.10.13 PRC-025 – Generator Relay Loadability. Revise the 3rd line of the paragraph under 4.11 TOP to read ‘directives to the GOP, and that the GOP will follow such directives. They also ensure GOPs render all available’. Capitalize ‘Real-time’ in the 6th line of the 1st paragraph and the 1st line of the 2nd bullet under 4.11.1.3 Requirement R7. Also replace ‘generator’ with ‘generation’ in the 9th line of the 1st paragraph and the last line of the 2nd paragraph of the same section. Delete the ‘in’ in the 6th line of the paragraph under 4.11.3.1 Requirement R3. Replace the ‘<’ with ‘less than’ in the 1st line of the 2nd bullet under 4.11.3.2 Requirement R13. Capitalize ‘Real-time’ in the 4th sentence of the 1st paragraph and the 1st line of the 2nd bullet under 4.11.3.3 Requirement R14. Replace the 6th line and part of the 7th line of the 1st paragraph with the following: ‘resources. The SDT recommends that the GOP notify the TOP of any unplanned changes in real output capabilities above 20 MVA at the aggregate Facility level.’ Replace ‘resources’ in the 1st line of the 2nd paragraph with ‘resource’. Replace ‘has’ with ‘have’ in the 2nd line of the 2nd paragraph under 4.11.3.4 Requirement R15. Replace the ‘>’ in the 2nd line of the paragraph under 4.11.4.1 Requirement R1 with ‘greater than’. Replace ‘has’ with ‘have’ in the 2nd line of the 2nd paragraph under 4.11.4.2 Requirement R2. Capitalize ‘Real-time’ in the 3rd and 5th lines of the 1st paragraph under 4.11.5 TOP-006 – Monitoring System Conditions. In the same section, also capitalize ‘Real-time’ in the 1st and 3rd lines of the 3rd bullet. Lastly, capitalize ‘Real-time’ in the 4th line of the 2nd paragraph of the same section. Replace the ‘<’ in the 2nd line of the 1st bullet of the same section with ‘less than’. Also in the 7th line of the 2nd paragraph, replace ‘less’ with ‘other’. In the next line, delete the ‘in’. Replace ‘resource’ with ‘resources’ in the 5th line of the paragraph under 4.13.1 VAR-001 – Voltage and Reactive Control (WECC Regional Variance). Do not change ‘occurs’ to ‘occur’. Replace ‘resource’ with ‘resources’ in the 5th line of the 1st paragraph under 4.13.2 VAR-002-2b – Generator Operation for Maintaining Network Voltage Schedules. Again, do not change ‘occurs’ to ‘occur’. Capitalize ‘Transmission’ in the last line of the 2nd paragraph. The paragraph under 4.13.3 shows up as part of the title of 4.13.4 in the clean version. Insert ‘of’ between ’30 minutes,’ and ‘any’ in the 1st line of what should be the paragraph under 4.13.3 VAR-002-2b – Requirement R3.1. Replace ‘changes’ with ‘change’ in the 2nd line of the same paragraph. Replace ‘is’ with ‘are’ in the 4th line of the same paragraph. We suggest rewording the 3rd paragraph under 4.14.1 CIP v5 to read: ‘During Project 2014-02 CIP Version 5 Revisions’ first comment period, the SDT received comments to modify the Applicability Section of CIP-003-6. The CIP SDT made drastic modifications in the second posting of CIP-003-6, which was posted for an additional 45-day comment and ballot period on September 3, 2014, to take into account all of the comments received during the first posting.’ ‘Responsible entity’ is capitalized extensively in 4.14.1 CIP v5 but it is not a defined term in the Glossary of Terms. Delete ‘The’ in the 4th line of the 4th paragraph under 4.14.1 CIP v5. Also, delete the ‘the’ in front of ‘Attachment 1’ in the last line of the same paragraph.

Exhibit F

Standard Drafting Team Roster for NERC Standards Development Project 2014-01

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Team Roster

Project 2014-01 Standards Applicability for Dispersed Generation Resources Standards Drafting Team

	Participant	Entity	Phone/Email
Chair	Tony Jankowski	We Energies W237N1500 Busse Road, Waukesha, WI 53188	262.544.7117 tony.jankowski@we-energies.com
Vice Chair	Tom Pruitt	Duke Energy 526 South Church Street Charlotte, NC 28202-1006	704.382.4676 tom.pruitt@duke-energy.com
Member	David Belanger	Exelon Generation 9 Summer Street Medway MA 02053	508.533.3924 david.belanger@exeloncorp.com
Member	George Brown	Acciona Energy North America 333 W. Wacker Dr, Suite 1500 Chicago, IL 60606 USA	312.673.3046 gbrown@acciona-na.com
Member	Stephen Enyeart	Bonneville Power Administration 7500 NE 41st Street, Suite 400 Vancouver Washington, 98662	360.619.6059 shenyeart@bpa.gov
Member	Brian Evans-Mongeon	Utility Services, Inc. 1080 Waterbury-Stowe Rd, Ste. 2; Waterbury, VT 05676	802.552.4022 brian.evans-mongeon@utilitysvcs.com
Member	Jessie Nevarez	Terra-Gen Operating Company 8560 Oak Creek Rd., Mojave, CA. 93501	661.822.2499 jnevarez@terra-genpower.com
Member	Jeffrey Plew	NextEra Energy Resources	561.904.3565

		700 Universe Blvd., Juno Beach, Fl 33408	jeffrey.plew@nexteraenergy.com
Member	Dana Showalter	E.ON Climate & Renewables 701 Brazos St, Ste 1400, Austin, TX 78701	512.482.4045 dana.showalter@eon.com
Member	Randhir Singh	PSEG Fossil 80 Park Plaza, Newark, NJ, 07102, T25	973.456.3546 347.241.0703 randhir.singh@pseg.com
Member	Eric White	MidAmerican Energy 666 Grand Avenue DMR7 Des Moines Iowa	515.281.2676 ewhite@midamre.com
NERC Staff	Katherine Street (Lead Standards Developer)	North American Electric Reliability Corporation 3353 Peachtree Road, N.E., Ste 600, North Tower Atlanta, Georgia 30326	404.446.9697 katherine.street@nerc.net
NERC Staff	Laura Anderson (Supporting Standards Developer)	North American Electric Reliability Corporation 3353 Peachtree Road, N.E., Ste 600, North Tower Atlanta, Georgia 30326	404.446.9671 laura.anderson@nerc.net
NERC Staff	Sean Cavote (Manager of Standards Development)	North American Electric Reliability Corporation 3353 Peachtree Road, N.E., Ste 600, North Tower Atlanta, Georgia 30326	404.446.9697 sean.cavote@nerc.net
PMOS	Gary Kruempel	MidAmerican Energy Company 4299 NW Urbandale Drive Des Moines, IA 50303	515-281-2510 GEKruempel@midamerican.com

FERC	Susan Morris	FERC	202.502.6803 susan.morris@ferc.gov
FERC	Tom Bradish	FERC	tom.bradish@ferc.gov