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

Monday, October 27, 2014, 1:00 p.m. to 5:00 p.m. Pacific
Tuesday, October 28, 2014, 9:00 a.m. to 5:00 p.m. Pacific

Las Vegas, Nevada

Dial-in: 866.740.1260 | Access Code: 4458510 | Security Code: 1979

Webinar: www.readytalk.com, enter access code 4458510

Administrative

1. **Introductions**
2. **Review NERC Antitrust Compliance Guidelines and Public Announcement***
3. **Participant Conduct Policy***
4. **Email List Policy***
5. **Review Meeting Agenda and Objectives***

Agenda Items

1. **Finalize PRC-004 and VAR-002 for Posting and Final Ballot***
   a. Discuss ballot results
   b. Finalize response to comments
   c. Finalize standard revisions
2. **Finalize PRC-005-X(X) For Posting**
3. **DGR/CIP SDT Coordination Update**
4. **Finalize Suggested RSAW Revisions***
   a. PRC-001, PRC-005, PRC-024, and PRC-025
5. **Legal Discussion** (S. Tyrewala)

6. **Update White Paper***

   a. CIP

   b. FAC

   c. MOD

   d. PRC

7. **Outreach***

8. **Future Meeting and Action Dates**

   a. Future SDT meeting dates and locations to be determined

9. **Adjourn**

*Background materials included.

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

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Public Announcements

For face-to-face meeting, with dial-in capability:
Participants are reminded that this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. The notice included the number for dial-in participation. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

Standards Development Process Participant Conduct Policy

I. General

To ensure that the standards development process is conducted in a responsible, timely and efficient manner, it is essential to maintain a professional and constructive work environment for all participants. Participants include, but are not limited to, members of the standard drafting team and observers.

Consistent with the NERC Rules of Procedure and the NERC Standard Processes Manual, participation in NERC's Reliability Standards development balloting and approval processes is open to all entities materially affected by NERC's Reliability Standards. In order to ensure the standards development process remains open and to facilitate the development of reliability standards in a timely manner, NERC has adopted the following Participant Conduct Policy for all participants in the standards development process.

II. Participant Conduct Policy

All participants in the standards development process must conduct themselves in a professional manner at all times. This policy includes in-person conduct and any communication, electronic or otherwise, made as a participant in the standards development process. Examples of unprofessional conduct include, but are not limited to, verbal altercations, use of abusive language, personal attacks or derogatory statements made against or directed at another participant, and frequent or patterned interruptions that disrupt the efficient conduct of a meeting or teleconference.

III. Reasonable Restrictions in Participation

If a participant does not comply with the Participant Conduct Policy, certain reasonable restrictions on participation in the standards development process may be imposed as described below.
If a NERC Standards Developer determines, by his or her own observation or by complaint of another participant, that a participant's behavior is disruptive to the orderly conduct of a meeting in progress, the NERC Standards Developer may remove the participant from a meeting. Removal by the NERC Standards Developer is limited solely to the meeting in progress and does not extend to any future meeting. Before a participant may be asked to leave the meeting, the NERC Standards Developer must first remind the participant of the obligation to conduct himself or herself in a professional manner and provide an opportunity for the participant to comply. If a participant is requested to leave a meeting by a NERC Standards Developer, the participant must cooperate fully with the request.

Similarly, if a NERC Standards Developer determines, by his or her own observation or by complaint of another participant, that a participant's behavior is disruptive to the orderly conduct of a teleconference in progress, the NERC Standards Developer may request the participant to leave the teleconference. Removal by the NERC Standards Developer is limited solely to the teleconference in progress and does not extend to any future teleconference. Before a participant may be asked to leave the teleconference, the NERC Standards Developer must first remind the participant of the obligation to conduct himself or herself in a professional manner and provide an opportunity for the participant to comply. If a participant is requested to leave a teleconference by a NERC Standards Developer, the participant must cooperate fully with the request. Alternatively, the NERC Standards Developer may choose to terminate the teleconference.

At any time, the NERC Director of Standards, or a designee, may impose a restriction on a participant from one or more future meetings or teleconferences, a restriction on the use of any NERC-administered list server or other communication list, or such other restriction as may be reasonably necessary to maintain the orderly conduct of the standards development process. Restrictions imposed by the Director of Standards, or a designee, must be approved by the NERC General Counsel, or a designee, prior to implementation to ensure that the restriction is not unreasonable. Once approved, the restriction is binding on the participant. A restricted participant may request removal of the restriction by submitting a request in writing to the Director of Standards. The restriction will be removed at the reasonable discretion of the Director of Standards or a designee.

Any participant who has concerns about NERC's Participant Conduct Policy may contact NERC's General Counsel.

NERC Email List Policy

NERC provides email lists, or "listservs," to NERC committees, groups, and teams to facilitate sharing information about NERC activities; including balloting, committee, working group, and drafting team work, with interested parties. All emails sent to NERC listserv addresses must be limited to topics that are directly relevant to the listserv group's assigned scope of work. NERC reserves the right to apply administrative restrictions to any listserv or its participants, without advance notice, to ensure that the resource is used in accordance with this and other NERC policies.

Prohibited activities include using NERC-provided listservs for any price-fixing, division of markets, and/or other anti-competitive behavior.[1] Recipients and participants on NERC listservs may not utilize NERC listservs for their own private purposes. This may include announcements of a personal nature, sharing of files or attachments not directly relevant to the listserv group's scope of responsibilities, and/or communication of personal views or opinions, unless those views are provided to advance the work of the listserv's group. Use of NERC's listservs is further subject to NERC's Participant Conduct Policy for the Standards Development Process.

- *Updated April 2013*

[1] Please see NERC's Antitrust Compliance Guidelines for more information about prohibited antitrust and anti-competitive behavior or practices. This policy is available at http://www.nerc.com/commondocs.php?cd=2

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	August 29, 2014	Applicability revised to clarify application of Requirements to BES dispersed power producing resources	Standard revised in Project 2014-01

Deleted: TBD

Standard PRC-004-4 — Protection System Misoperation Identification and Correction

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).

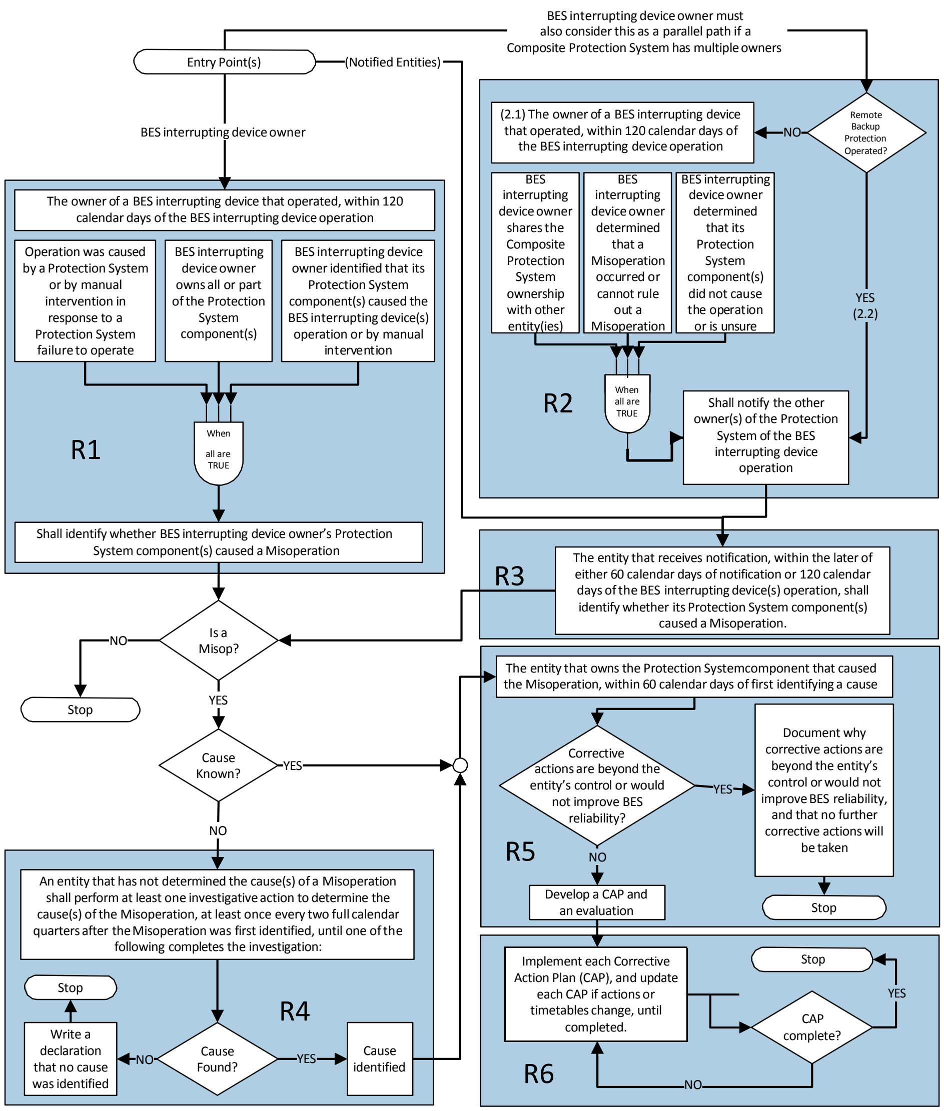
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance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



Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources

The Project 2014-01 Standards Applicability for Dispersed Generation Resources Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from September 5, 2014 through October 22, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 24 sets of comments, including comments from approximately 77 different people from approximately 55 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 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 additional ballot results. There are, however, 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 clarified its recommendations in response to some comments, to further describe 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 has addressed each identified typographical and formatting error as appropriate in the posted redlined standards.

At least one commenter requested that the red-lined version of the standard posted limit red-lined text to those changes made by the DGR SDT.

The DGR SDT appreciates the suggestion. 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 and plans to use a similar format for other standards.

The DGR SDT appreciates the suggestion, and 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 2 and Requirement 3 should add "in response to electrical quantities."

The DGR SDT appreciates the suggestion, however, notes that relays that respond to “electrical quantities” is included in the definition of Protection System as a defined by the NERC Glossary of Terms, therefore, the DGR SDT elects to retain the language as drafted to avoid the 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.”

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.

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 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."

Further discussion at in-person meeting

(Note: NERC Glossary definition—Facility--a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

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 appreciates the comment, and drafted the standard 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 SDT appreciates the suggestion, however, the SDT maintains this issue is adequately addressed through the NERC Glossary term BES definition. 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. "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." (NERC filings and FERC order, docket RD14-2).

NERC December 13, 2013 filing, page 15 describes Inclusion I4 (Dispersed Power Producing Resources) as follows: "Dispersed power producing resources are small-scale 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."

NERC December 13, 2013 filing, page 17 inclusion of variable generation resources regarding the purpose of inclusion I4 as follows: "Consistent with the Commission's recognition that the purpose of Inclusion I4 is to include variable generation, all forms of generation resources, including variable generation resources, continue to be included in the proposed revisions to the BES Definition....Given the increasing penetration of wind, solar, and other non-traditional forms of generation, the standard drafting team believes that continuing the inclusion of individual variable generation units within the scope of a bright-line BES Definition is appropriate to ensure that, where necessary to support reliability, these units may be subject to Reliability Standards."

NERC January 25, 2012 filing, page 18 states: "Inclusion I4 – This inclusion was added to the BES Definition in order to accommodate the effects of variable generation on the BES. The purpose of this inclusion is to include variable generation (e.g., wind and solar resources)."

FERC Order Approving Revised Definition, Docket No. RD14-2-000, Issued March 20, 2014, P 18: "NERC states that all forms of generation resources, including variable generation resources, continue to be included in the proposed revisions to the definition. NERC states that this conclusion is consistent with the Commission's recognition in Order No. 773 that the purpose of inclusion I4 is to include variable generation. Thus, NERC revised inclusion I4 to clarify its original intent and to reflect the Commission's statements in Order No. 773 regarding its scope. NERC observes that the Commission in Order No. 773 noted that, 'owners and operators of these resources that meet the 75 MVA gross aggregate nameplate rating threshold are, in some cases, already registered and have compliance responsibilities as generator owners and generator operators.'[1] According to NERC, given the increasing use of wind, solar, and other non-traditional forms of generation, NERC believes that 'continuing the inclusion of individual variable generation units within the scope of the definition is appropriate to ensure that, where necessary to support reliability, these units may be subject to Reliability Standards.'"

NERC Petition at 18, quoting Order No. 773, 141 FERC ¶ 61,236 at P 115.

P 47: "...We agree with NERC that, given the increasing presence of wind, solar, and other non-traditional forms of generation, continuing the inclusion of individual variable generation units within the scope of the definition is appropriate to ensure that, where necessary to support reliability, these units may be subject to Reliability Standards. Moreover, inclusion I4 is limited to individual resources that aggregate to a total capacity greater than 75 MVA, the same threshold applicable to other types of generating resources."

At least one commenter expressed a concern regarding VAR-002.

The DGR SDT appreciates the comment, however, refers the commenter to the posted consideration of comments document for VAR-002, where the DGR SDT provided a response to the particular concern expressed by the commenter.

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

Group/Individual		Commenter	Organization	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.	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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
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

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.	Stephanie Johnson	Westar Energy, Inc.	SPP	1, 3, 5, 6
2.	Bo Jones	Westar Energy, Inc.	SPP	1, 3, 5, 6
3.	Tiffany Lake	Westar Energy, Inc.	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
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:

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:

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 Misoperations affected an aggregate nameplate rating of less than or equal to [delete “75”] 20 MVA of BES facilities, this requirement does not apply.”

Organization	Yes or No	Question 1 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 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	
Puget Sound Energy	Yes	

Organization	Yes or No	Question 1 Comment
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	
Consumers Energy Company	Yes	

Organization	Yes or No	Question 1 Comment
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:

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.
ISO New England	No	See Question 1 response
Northeast Power Coordinating	Yes	

Organization	Yes or No	Question 2 Comment
Council		
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	
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

Organization	Yes or No	Question 2 Comment
		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:

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	
Dominion	No	
DTE Electric Co.	No	
EDP Renewables North America LLC	No	
American Electric Power	No	
Idaho Power	No	
Tacoma Power	No	
Manitoba Hydro	No	

Organization	Yes or No	Question 3 Comment
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 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

Organization	Yes or No	Question 3 Comment
		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 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-

Organization	Yes or No	Question 3 Comment
		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 System' in PRC-004-4. We felt these suggestions would help maintain consistency with the current documentation and the BES Definition.

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

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 September 30, 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.

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Deleted: in May 2014 and is pending regulatory approval

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	8/27/2014	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised
5	10/28/14	Revised under Project 2014-01 to update Description of Current Draft and Rationale box to reflect date of FERC approval of VAR-002-3, inserted the word "Requirement" in the first line of the bullet under Requirement R4, between the terms "in" and "R4", and deleted the term 'transformers' following the phrase 'its step-up' in M5.	Revised

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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, and was subsequently approved by FERC and became effective September 30, 2014.

Deleted: 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

[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.

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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.

Deleted: August 27

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.

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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.

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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.

Deleted: transformers

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.

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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.

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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

Deleted: May 30,

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.

Deleted: May 30,

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.

Deleted: May 30,

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

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Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

Deleted: May 30

NERC
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RELIABILITY CORPORATION

Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources
VAR-002-4 and VAR-002-2b(X)

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—b(X) were posted for a 45-day comment period from August 27 through October 16, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 18 responses, including comments from approximately 88 different people 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. ~~The SDT is proceeding with balloting VAR-002-2b(X) because of differences in the way standards become enforceable in certain Canadian jurisdictions. The intent of VAR-002-2b(X) as approved by balloters is to file it upon NERC Board of Trustees adoption only in those Canadian jurisdictions that do not tie their enforcement dates to FERC approval.~~

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.

1. Summary Consideration

[1] The terms "dispursed generation resources" and "dispersed power producing resources" are used interchangeably.

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 VAR-002 Reliability Standard as evidenced by recent 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. However, all recommended changes are non-substantive 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 the posted high-priority standards. The DGR SDT has addressed each identified typographical and formatting error as appropriate in the posted redlined standards.

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 in the 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.

The DGR SDT thanks the commenter for the suggestion. 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, 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 prudent, 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 use of 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 SDT appreciates the suggestion, however, the SDT maintains this issue is adequately addressed through the NERC Glossary term BES definition. 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. "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." (NERC filings and FERC order, docket RD14-2).

NERC December 13, 2013 filing, page 15 describes Inclusion I4 (Dispersed Power Producing Resources) as follows: "Dispersed power producing resources are small-scale 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."

NERC December 13, 2013 filing, page 17 inclusion of variable generation resources regarding the purpose of inclusion I4 as follows: "Consistent with the Commission's recognition that the purpose of Inclusion I4 is to include variable generation, all forms of generation resources, including variable generation resources, continue to be included in the proposed revisions to the BES Definition....Given the increasing penetration of wind, solar, and other non-traditional forms of generation, the standard drafting team believes that continuing the inclusion of individual variable generation units within the scope of a bright-line BES Definition is appropriate to ensure that, where necessary to support reliability, these units may be subject to Reliability Standards."

NERC January 25, 2012 filing, page 18 states: "Inclusion I4 – This inclusion was added to the BES Definition in order to accommodate the effects of variable generation on the BES. The purpose of this inclusion is to include variable generation (e.g., wind and solar resources)."

FERC Order Approving Revised Definition, Docket No. RD14-2-000, Issued March 20, 2014, P 18: "NERC states that all forms of generation resources, including variable generation resources, continue to be included in the proposed revisions to the definition. NERC states that this conclusion is consistent with the Commission's recognition in Order No. 773 that the purpose of inclusion I4 is to include variable generation. Thus, NERC revised inclusion I4 to clarify its original intent and to reflect the Commission's statements in Order No. 773 regarding its scope. NERC observes that the Commission in Order No. 773 noted that, 'owners and operators of these resources that meet the 75 MVA gross aggregate nameplate rating threshold are, in some cases, already registered and have compliance responsibilities as generator owners and generator operators.'[1] According to NERC, given the increasing use of wind, solar, and other non-traditional forms of generation, NERC believes that 'continuing the inclusion of individual variable generation units within the scope of the definition is appropriate to ensure that, where necessary to support reliability, these units may be subject to Reliability Standards.'"

NERC Petition at 18, quoting Order No. 773, 141 FERC ¶ 61,236 at P 115.

P 47: "...We agree with NERC that, given the increasing presence of wind, solar, and other non-traditional forms of generation, continuing the inclusion of individual variable generation units within the scope of the definition is appropriate to ensure that, where necessary to support reliability, these units may be subject to Reliability Standards. Moreover, inclusion I4 is limited to individual resources that aggregate to a total capacity greater than 75 MVA, the same threshold applicable to other types of generating resources."

P 48: "...The purpose of inclusion I4 is to include all forms of variable generation resources. As we noted in Order No. 773, there are geographical areas that depend on these types of generation resources for the reliable operation of the interconnected transmission network..."

Some commenters expressed concern that VAR-002 states non-applicability of the standard for dispersed generation resources identified through Inclusion I4 of the BES definition, and indicated that the bullet added to subpart 3.1 exempts all I4 generators from reporting on their VAR capability status. The commenters 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 commenters 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 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, instead it should apply at the 75MVA Aggregate level. In addition, other standards, such as proposed TOP-003, require the Generator Operator to provide real time data as directed by the TOP. 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 aptly 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 appreciates the suggestion, however, the DGR SDT is of the understanding that the generation facilities subject to Inclusion I4 of the Bulk Electric System definition are comprised of individual generating units that are controlled by central AVRs or Volt/Var controllers, and are not directed by individual AVR, power system stabilizer or alternative voltage controlling devices at the individual generating units.

The DGR SDT further maintains that is not prudent to extend the exception addressed in the footnote in Requirement R4 to Requirement R3. This is so, because, AVR functionality may be accomplished at the individual unit, therefore, excluding individual units from Requirement R3 potentially creates a situation whereby status changes for AVRs or other voltage controlling devices for each individual generating unit of a DGR are not accounted for.

At least one commenter suggested adding the terms from footnotes in the standard to the NERC Glossary.

The SDT appreciates the suggestion, however, adding definitions to the NERC Glossary is beyond the scope of the SDT.

Some commenters suggested revisions to, or elimination of, footnotes in the standard.

The SDT appreciates the suggestion, however, revising or eliminating footnotes in the standard as suggested is beyond the scope of the SDT.

At least one commenter does not agree with the deletion of the rationales used for the previous version of the standard and asserts that the rationales are still needed in the standard.

The DGR SDT appreciates the suggestion, however, the DGR SDT has determined that the rationale information included in previous versions of the standard is available as appropriate in other associated documents, such as the White Paper.

At least one commenter requests the DGR SDT revise either R4 or R5 regarding placement of exclusion language for consistency, noting that, in Requirement R4 the exclusion statement is a bulleted item within the requirement text, and that in Requirement R5 the exclusion statement is a footnote at the bottom of the page.

The DGR SDT appreciates the suggestion, however, the SDT maintains that, as the purpose of each item is unique with respect to the other, it is prudent 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, however, the purpose of the footnote in Requirement R5 is to clarify the applicability of that Requirement.

At least one commenter requested that 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...” for consistency with VAR-002-2b(x), Requirement R4 VSL levels.

The SDT appreciates the suggestion, however, revising the Violation Severity Levels (VSLs) as suggested is beyond the scope of the SDT.

At least one commenter suggested revision to the Requirement R4 Severe VSL to replace the word "any" with "all" in the first statement.

The SDT appreciates the suggestion, however, revising the Violation Severity Levels (VSLs) as suggested is beyond the scope of the SDT.

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]

[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								
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

		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

		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

Group/Individual		Commenter	Organization	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

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

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	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:

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 improve voltage performance at the point of interconnection", which is

Organization	Yes or No	Question 1 Comment
		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 comply with the standard without the proposed changes, and no reliability

Organization	Yes or No	Question 1 Comment
		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	
EDP Renewables North America LLC	Yes	

Organization	Yes or No	Question 1 Comment
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:

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

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 February 13, 2014 – March 14, 2014.
2. The draft standard was posted for a 45-day concurrent comment and ballot period of April 17, 2014–June 3, 2014.

Description of Current Draft

The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is posting draft 2 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 Project 2014-01, Standards Applicability for Dispersed Generation Resources, will post an applicability change to PRC-005-2 and PRC-005-3 for comment and ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Ballot	April 17 – June 2, 2014
45-day Additional Formal Comment Period with Parallel Ballot (if necessary)	July 30, – September 12, 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.

Rationale for Applicability Section: This section does not reflect the applicability changes that will be proposed by the Project 2014-01 Standards Applicability for Dispersed Generation Resources standards drafting team. The changes in this posted version and those being made by the Project 2014-01 standards drafting team do not overlap.

Additionally, to align with ongoing NERC standards development in Project 2010-05.2: Special Protection Systems, the term “Special Protection Systems” in PRC-005-X was replaced by the term “Remedial Action Schemes.” These terms are synonymous in the NERC Glossary of Terms.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

4.2. Facilities:

4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.

4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, including:

4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems and Sudden Pressure Relaying for 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 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 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 relevant BES generating unit where the Automatic Reclosing is applied.

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

4.2.6.2 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 RAS 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.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

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: In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 3.1 and its subparts have been removed and have not been reinserted into the implementation plan.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through

1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

Rationale for R4 Part 4.1: In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 4.1 and its subparts have been removed and have not been reinserted into 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 implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the 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.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated 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, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

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 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 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 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.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. Regional Variances

None.

E. Interpretations

None.

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)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)

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

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
X			Project 2007-17.3 – Revised to address the FERC directive in Order No. 758 to include sudden pressure relays in maintenance programs.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[3]**	**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.

[3] 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.

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 RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • 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 RAS, 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 RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • 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 RAS, 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>
<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 RAS, 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="2">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>
</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 RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • 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 RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

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), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS 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 RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring

In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	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 RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 5 Maintenance Activities and Intervals for Sudden Pressure Relaying Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

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, 2013 – December 19, 2013.
2. The draft standard was posted for a 45-day concurrent comment and ballot period of June 12, 2014–July 29, 2014.
3. PRC-005-3(X) passed a final ballot, which was posted for a 10-day ballot period of August 27, 2014-September 5, 2014.

Description of Current Draft

The Dispersed Generation Resources Standard Drafting Team (DGR SDT) is posting draft 1 of PRC-005-4(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.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Ballot	October 28 – November 11, 2014
45-day Additional Formal Comment Period with Parallel Ballot (if necessary)	November 30, – December 12, 2014
Final ballot	January 2015
BOT adoption	February 2015

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Deleted: A parallel effort in the Project 2014-01, Standards Applicability for Dispersed Generation Resources, will post an applicability change to PRC-005-2 and PRC-005-3 for comment and ballot.
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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.

None

Deleted: **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. ¶

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A. Introduction

1. **Title: Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**

2. **Number: PRC-005-4(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

   4.2. Facilities:

   4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

   4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

   4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

   4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.

   4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, for generators not identified through Inclusion I4 of the BES definition including:

   4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

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 generator Facilities. These applicability revisions are intended clarify and provide for consistent application of the Requirements t BES generator Facilities included i the BES through Inclusion I4 – Dispersed power producing resour

This version is labeled PRC-005-3(X for balloting purposes. The 'X' indicates that a version number w be applied at a later time, because

Rationale for 4.2.5: In order to differentiate between typical BES generator Facilities and BES generato 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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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.¶

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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.¶
Rationale for Applicability Section: This section does not reflect the applicability changes that will be proposed by the Project 2014-01 Standards Applicability for Dispersed Generation Resources standards drafting team. The changes in this posted version and those being made by the Project 2014-01 standards drafting team do not overlap. ¶
Additionally, to align with ongoing NERC standards development in Project 2010-05.2: Special Protection Systems, the term "Special Protection Systems" in PRC-005-X was replaced by the term "Remedial Action Schemes." These terms are synonymous in the NERC Glossary of Terms. ¶

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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 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 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Protection Systems 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 or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group. [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.

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[1] Automatic Reclosing addressed in Section 4.2.7.1, 4.2.7.2 and 4.2.7.3 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

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

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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.

Deleted: **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

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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]*

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M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the 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

Deleted: **Rationale for R3 Part 3.1:** In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 3.1 and its subparts have been removed and have not been reinserted into the implementation plan.

Deleted: **Rationale for R4 Part 4.1:** In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 4.1 and its subparts have been removed and have not been reinserted into the implementation plan.

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limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated 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, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

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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

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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

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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 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 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 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.

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. Regional Variances

None.

E. Interpretations

None.

F. Supplemental Reference Documents

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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)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)

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	

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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

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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
X			Project 2007-17.3 – Revised to address the FERC directive in Order No. 758 to include sudden pressure relays in maintenance programs.

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Table 1-1

Component Type - Protective Relay
Excluding distributed UFLS and distributed UVLS (see Table 3)

Component Attributes	Maximum Maintenance Interval[3]	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.

[3] 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.

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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.

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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

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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.

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Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • 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

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Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	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.

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Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • 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

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Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	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.

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Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **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

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Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

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Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • 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.

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Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

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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.

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Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS 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 RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

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Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

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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.

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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.

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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.

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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 RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

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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 RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

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Table 5 Maintenance Activities and Intervals for Sudden Pressure Relaying Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

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PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, 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.

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Compliance Questionnaire and
Reliability Standard Audit Worksheet

PRC-001-1.1 — System Protection Coordination

Registered Entity: *(Must be completed by the Compliance Enforcement Authority)*

NCR Number: *(Must be completed by the Compliance Enforcement Authority)*

Applicable Function(s): **BA, TOP, GOP**

Auditors:

Disclaimer

NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

Subject Matter Experts

Identify your company's subject matter expert(s) responsible for this Reliability Standard. Include the person's title, organization and the requirement(s) for which they are responsible. Insert additional lines if necessary.

Response: ***(Registered Entity Response Required)***

SME Name	Title	Organization	Requirement

Reliability Standard Language

PRC-001-1.1 — System Protection Coordination

Purpose:
To ensure system protection is coordinated among operating entities.

Applicability:
Balancing Authorities
Transmission Operators
Generator Operators

NERC BOT Approval Date: 11/1/2006

FERC Approval Date: 3/16/2007

Reliability Standard Enforcement Date in the United States: 4/1/2013

Requirements:

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

Describe, in narrative form, how you meet compliance with this requirement: *(Registered Entity Response Required)*

Question:
Who are the Transmission Operator, Generator Operator, and Balancing Authority personnel identified as being familiar with the purpose and limitations of Protection System schemes applied in their area? Please provide the job titles of identified personnel.

Registered Entity Response (Required):

R1 Supporting Evidence and Documentation

Response: ***(Registered Entity Response Required)***

Provide the following: Document Title and/or File Name, Page & Section, Date & Version

Title	Date	Version

Audit Team: Additional Evidence Reviewed:

This section must be completed by the Compliance Enforcement Authority.

Compliance Assessment Approach Specific to PRC-001-1.1 R1.

___ Verify the identified personnel are familiar with:
___ The purpose of relay protection schemes applied in its area.
___ The limitations of relay protection schemes applied in its area.

(Protection System schemes shall include, but are not limited to, Special Protection Systems within its area.)

Note to auditor: Auditors shall use their professional judgment to determine whether identified personnel are familiar with the purpose and limitations of Protection System schemes applied in its area. Identified Generator Operator personnel should be familiar with the purpose and limitations of its generator protection system and any associated generator interconnection Facilities. In general, the purpose of relay protection schemes relates to what type of fault the protection system will detect (ground fault, phase to phase fault, failure to clear fault, backup etc.) and how the detection is accomplished (measure impedance of fault, differential measurement, etc.). Examples of limitations could include, but are not limited to, a Zone 1 relay typically being set to detect faults up to about 80% of a line, or a transformer differential relay only detecting a fault between two current transformers on each side of the transformer bank. Evidence may include, but is not limited to, training records and personnel interviews, training with an overview of the different types of protection used on the system for generators, transmission line(s), and transformers on the entity's system. Also, an overview of the zones of protection, fault locations and which relay would operate based on the location is desirable. If the entity has Special Protection Systems (SPSs), any training could include an overview of the SPS's operation, arming and disarming of the SPS and how to verify which mode is in service. Documentation of any training provided should be specific training on the purpose of protection systems and limitations associated with the entity's system. Auditors need reasonable assurance that the required familiarity exists at the functional level (TOP, BA, GOP) of the entity. An interview of all identified personnel, or a statistical sample thereof, may be performed, but is not required.

Auditor's Detailed Notes:

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

Describe, in narrative form, how you meet compliance with this requirement: ***(Registered Entity Response Required)***

Question – Did you have an equipment or relay failure during the audit period which reduced system reliability? If yes, provide evidence you notified the proper entities.

Entity Response: ***(Registered Entity Response Required)***

R2 Supporting Evidence and Documentation

Response: ***(Registered Entity Response Required)***

Provide the following:
Document Title and/or File Name, Page & Section, Date & Version

Title	Date	Version

Audit Team: Additional Evidence Reviewed:

This section must be completed by the Compliance Enforcement Authority.

Compliance Assessment Approach Specific to PRC-001-1.1 R2.

___ Verify the entity took the following actions related to a relay or equipment failure that reduced system reliability:

- ___ (R2.1) Generator Operator notified its Transmission Operator and Host Balancing Authority and
- ___ Generator Operator took corrective action as soon as possible.
- ___
- ___ (R2.2) Transmission Operator notified its Reliability Coordinator and affected Transmission Operators and Balancing Authorities and
- ___ Transmission Operator took corrective action as soon as possible.

Auditor's Detailed notes:

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- 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.

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R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

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Describe, in narrative form, how you meet compliance with this requirement: *(Registered Entity Response Required)*

Question: Have you made changes to new or added new Protective Systems during the audit period? If yes, provide evidence you coordinated with the appropriate entities.

Note to Auditor:
Per R3.1, Coordination by a Generator Operator of new protection systems or protection system changes on individual generating units of dispersed power producing resources identified thorough Inclusion I4 of the BES Definition with its Transmission Operator and host Balancing Authority is not required.

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Entity Response: *(Registered Entity Response Required)*

R3 Supporting Evidence and Documentation

Response: *(Registered Entity Response Required)*

Provide the following:
Document Title and/or File Name, Page & Section, Date & Version

Title	Date	Version

Audit Team: Additional Evidence Reviewed:

This section must be completed by the Compliance Enforcement Authority.

Compliance Assessment Approach Specific to PRC-001-1.1 R3.

___ Verify the entity coordinated new Protective Systems and changes as follows:

___ Each Generator Operator coordinated with its Transmission Operator and Host Balancing Authority.

(Coordination by a Generator Operator of new protection systems or protection system changes on individual dispersed power producing resources identified in Inclusion I4 of the BES Definition with its Transmission Operator and host Balancing Authority is not required). *Consider adding as footnote?*

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___ Each Transmission Operator coordinated with neighboring Transmission Operators and Balancing Authorities.

Auditor's Detailed notes:

R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

Describe, in narrative form, how you meet compliance with this requirement: *(Registered Entity Response Required)*

R4 Supporting Evidence and Documentation

Response: *(Registered Entity Response Required)*

Provide the following:
Document Title and/or File Name, Page & Section, Date & Version

Title	Date	Version

Audit Team: Additional Evidence Reviewed:

This section must be completed by the Compliance Enforcement Authority.

Compliance Assessment Approach Specific to PRC-001-1.1 R4.

___ Verify each Transmission Operator coordinated Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

Auditor's Detailed notes:

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

Describe, in narrative form, how you meet compliance with this requirement: *(Registered Entity Response Required)*

Question: Did you experience changes in operating conditions that could require changes of Protection Systems of other entities? If yes, provide evidence of coordination.

Entity Response: *(Registered Entity Response Required)*

R5 Supporting Evidence and Documentation

Response: ***(Registered Entity Response Required)***

Provide the following:
Document Title and/or File Name, Page & Section, Date & Version

Title	Date	Version

Audit Team: Additional Evidence Reviewed:

This section must be completed by the Compliance Enforcement Authority.

Compliance Assessment Approach Specific to PRC-001-1.1 R5.

___ Verify each Generator Operator or Transmission Operator coordinated changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others.

___ Verify the Generator Operator notified its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

___ Verify the Transmission Operator notified neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

Auditor's Detailed notes:

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

Describe, in narrative form, how you meet compliance with this requirement: ***(Registered Entity Response Required)***

R6 Supporting Evidence and Documentation

Response: ***(Registered Entity Response Required)***

Provide the following:
Document Title and/or File Name, Page & Section, Date & Version

Title	Date	Version

Audit Team: Additional Evidence Reviewed:

This section must be completed by the Compliance Enforcement Authority

Compliance Assessment Approach Specific to PRC-001-1.1 R6.

___ Verify the entity monitors the status of each Special Protection System in its area.

___ Verify the entity notified affected Transmission Operators and Balancing Authorities of each change in status.

Auditor's Detailed notes:

Supplemental Information

Other - The list of questions above is not all inclusive of evidence required to show compliance with the Reliability Standard. Provide additional information here, **as necessary** that demonstrates compliance with this Reliability Standard.

Entity Response: ***(Registered Entity Response)***

Compliance Findings Summary (to be filled out by auditor)

Req.	NF	PV	OEA	NA	Statement
1					
2					
3					
4					
5					
6					

Excerpts from FERC Orders -- For Reference Purposes Only
Updated Through March 31, 2009
PRC-001-1

Order 693

P 1418. Protection and Control systems (PRC) on Bulk-Power System elements are an integral part of reliable grid operation. Protection systems are designed to detect and isolate faulty elements on a system, thereby limiting the severity and spread of system disturbances, and preventing possible damage to protected elements. The function, settings and limitations of a protection system are critical in establishing SOLs and IROLs. The PRC Reliability Standards apply to transmission operators, transmission owners, generator operators, generator owners, distribution providers and regional reliability organizations and cover a wide range of topics related to the protection and control of power systems.

P 1419. PRC-001-1 ensures that protection systems are coordinated among operating entities by requiring transmission and generator operators to notify appropriate entities of relay or equipment failures that could affect system reliability. In addition, transmission and generator operators must coordinate with appropriate entities when new protection systems are installed, or when existing protection systems are modified.

P 1433. The Commission approves PRC-001-1 as mandatory and enforceable….

P 1435. Protection systems on Bulk-Power System elements are an integral part of reliable operations. They are designed to detect and isolate faulty elements on a power system, thereby limiting the severity and spread of disturbances and preventing possible damage to protected elements. If a protection system can no longer perform as designed because of a failure of its relays, system reliability is reduced or threatened. In deriving SOLs and IROLs, moreover, the functions, settings, and limitations of protection systems are recognized and integrated. Systems are only reliable when protection systems perform as designed. This is what PRC-001-1 means in linking a reduction in system reliability with a protection relay failure or other equipment failure.

P 1436. … we note that while the PRC Reliability Standards do not specifically require protection systems consisting of redundant and independent protection groups for each critical element in the Bulk-Power System, such requirements are included as one potential solution in the TPL Reliability Standards.

P 1438. In the case, … of a system element protected by a single protection System with a failed relay that threatens system reliability, that scenario would require the use of appropriate operating solutions including removing a system element from service. Another possible solution is to operate a system at a lower SOL or IROL that recognizes the degraded protection performance.

P 1439. Corrective actions taken by transmission operators to return a system to a secure operating state when a protective relay or equipment failure reduces system reliability normally refer to “operator control actions”, consisting of operator actions such as removing the facility without protection from service, generation redispatch, transmission re-configuration, etc. Corrective action must be completed as soon as possible, but no longer than 30 minutes after a notice of protection system failure. Failure to complete corrective action within

30 minutes will be considered a violation of the relevant IROL or TOP Reliability Standards. In contrast, troubleshooting or replacing failed relays or equipment are performed by field maintenance personnel and normally take hours or even days to complete. These actions are not normally considered corrective actions in the context of real-time operation of the Bulk-Power System.

P 1440. We believe that "[t]he transmission operator shall take corrective action as soon as possible" refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System.

P 1442. We agree … that generator operators do not have the same ability as transmission operators to take corrective control actions on the Bulk-Power System…

P 1443. As explained above, the requirement for system operators to take corrective control action when protective relay or equipment failure reduces system reliability should be treated the same as the requirement for returning a system to a secure and reliable state after an IROL violation, i.e., as soon as possible, but no longer than 30 minutes after a violation. A longer time limit would place an entity in violation of relevant IROL or TOP Reliability Standards.

P 1448. … The time allowed for mitigating actual IROL violations is very clear: as soon as possible and within 30 minutes. We clarify that our concern is not about "field protection and control personnel not being alerted about failure of relays and protection systems on critical elements." Our focus, rather, is that upon detection of failure of relays and protection systems on critical elements, field personnel must report the failures promptly to the transmission operators so that corrective operator control actions can be taken as soon as possible and within 30 minutes… with respect to …[concerns] that our proposed directives would result in local-level personnel undermining or not following the instructions of reliability coordinator personnel at a time when the system is unstable, we do not understand how local level personnel, who have no operating control of a transmission operator's system or a reliability coordinator's system could do so.

P 1449. The Commission approves Reliability Standard PRC-001-1 as mandatory and enforceable. …

June 8, 2007 Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, Docket No. RR07-11-000

P 87. We note that upon failure of protective relays, NERC Reliability Standard PRC-001-1 requires transmission operators and generator operators to take corrective actions as soon as possible (within thirty minutes as directed by Order No. 693). Order No. 693 clarifies that "corrective actions" do not refer to the repair of protective relays, but instead to actions that ensure the reliability of the system, such as lowering IROLs and SOLs. The proposed regional Reliability Standard does not relieve compliance with this requirement but, rather, adds more stringency by defining a maximum timeframe for removal and repair of protective equipment.

February 3, 2012 Order Approving Revised Definition of Protection System, Docket No. RD11-13-000

P 5. The current definition of Protection System includes protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry. The revised definition with the proposed modification states:

"Protection System –

- 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 breaker or other interrupting devices."

P 9. The Commission finds that the ERO's modification to the definition of Protection System is just, reasonable, not unduly discriminatory or preferential, and in the public interest. As explained by NERC, battery chargers are essential to assure that batteries used to operate protection systems are in a continuous state of readiness. Therefore, it is appropriate that battery chargers be included in the definition of Protection System. The modified definition removes any uncertainty as to whether battery chargers should be included in a responsible entity's maintenance and testing program and, therefore, closes a reliability gap identified by NERC.

Revision History

Version	Date	Reviewers	Revision Description
1	October 2009	RSAW Working Group	New Document.
1	December 2010	QRSAW WG	Revised Findings Table, modified Supporting Evidence tables, and added Revision History.
1	January 2011	Craig Struck	Reviewed for format consistency and content.
1.1	September 2011	Craig Struck	Format changes for 2012.
1.2	October 2013	ECEMG	Clarified auditor guidance for R1 and R3. Other minor changes to format and wording.
1.3	February 2014	ECEMG	Clarified auditor guidance for R1.
1.4	April 2014	RSAWTF	Errata associated with Project 2007-17 regarding revised definition of "Protection System."

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standard Audit Worksheet[1]

PRC-025-1 – Generator Relay Loadability

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: [On-site Audit | Off-site Audit | Spot Check]
Names of Auditors: Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1		X[3]	X									X[3]			

Facilities:

The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

- Generating unit(s).
- Generator step-up (i.e., GSU) transformer(s).
- Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[4]

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[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.
[3] Entity that applies load-responsive protective relays at the terminals of the Elements listed in, Facilities.

- Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
- Elements utilized in the aggregation of dispersed power producing resources.

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

[4] These transformers are variable referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
A list of all load-responsive protective relays.
Summaries of calculations, spreadsheets, simulation reports, settings sheets, or other evidence that settings for each load responsive relay were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-025-1, R1
This section to be completed by the Compliance Enforcement Authority

	(R1) For all, or a sample of, load-responsive protective relays, examine evidence and verify the following:

	• Entity used appropriate elements from PRC-025-1 – Attachment 1: Relay Settings, and that the evidence identifies the criteria in Table 1 (e.g., application, relay type, option, voltage, Real Power, Reactive Power, and Pick up setting).
	• Entity applied the settings consistent with the criteria according to PRC-025-1 – Attachment 1: Relay Settings

Note to Auditor: Ownership of load-responsive protective relays is determined at the terminals of the Elements listed in Facilities section. Determine applicability of relay protection elements as detailed in PRC-025-1 – Attachment 1, Relay Settings. The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals.

For load-responsive protective relays utilized on individual dispersed power producing resources identified under Inclusion I4 of the BES definition, an entity may provide evidence for a single sample generating unit within a dispersed facility rather than providing documentation for each individual unit, provided the entity used that methodology to set its protective relays for all its BES generators.

Auditor Notes:

Additional Information:

Reliability Standard

PRC-025-1.pdf

The full text of PRC-025-1 may be found on the NERC Web Site (www.nerc.com) under “Program Areas & Departments”, “Reliability Standards.”

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language

Order No. 799. *Generator Relay Loadability and Revised Transmission Relay Loadability Standards*, 148 FERC ¶ 61,042 (2014).
http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Final%20Rule%20PRC-025-1%20and%20PRC-023-3.pdf

P 2 In approving the Standard, FERC found “that the new standard on generation loadability, Reliability Standard PRC-025-1, will enhance reliability by imposing mandatory requirements governing generator relay loadability, thereby reducing the likelihood of premature or unnecessary tripping of generators during system distrubances.”

P 9 During the discussion of PRC-025-1, FERC stated “For most applications of each type of relay [e.g., synchronous or asynchronous generator, generator step-up transformer, or unit auxiliary transformer], the proposed standard would give applicable entities the option of adopting relay settings that meet the stated criteria as determined through: (1) a relatively simple calculation; (2) a more complex calculation; or (3) a described simulation.”

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	08/29/2014	NERC Compliance, RSAWTF, CMFG, ECEMG	New Document

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

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, 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 Power Producing 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, 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 (relevant versions)[4];
- PRC-005 (relevant versions)[5]; and
- VAR-002 (relevant versions)[6].

[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 revised as part of Project 2010-05.1 Protection Systems: Misoperations.
[5] Reliability Standard PRC-005 is currently being revised as part of Project 2007-17.3 – Protection System Maintenance and Testing – Phase 3.
[6] Reliability Standard VAR-002 is currently being revised as part of Project 2013-04 – Voltage and Reactive Control.

However, the SDT has recognized that many 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 BES definition. The proposed resolutions target the applicability of the standard noted in the language of the applicability section or specifically target 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 effort.

The technical section of this paper includes insight from the SDT review, including the history of standards applicability to dispersed power producing 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.

[7] See Appendix B.

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[8] 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.[9] 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 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.
[9] *North American Electric Reliability Corporation*, 138 FERC ¶ 61,193 at P 81 (2012).

3 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'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 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,[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 providing an alternative to, or an enhancement of, the traditional electric power*

[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.

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 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

[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).

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 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.[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 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 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 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

[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

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, 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 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 July 2, 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.

Commented [SC1]: Verify accuracy of table.

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 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.

3.3.3 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 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.

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.

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 generation 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 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.*

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 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 resources.*

Commented [SC2]: Tony to review COM-002-4.

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 generation 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 generation 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 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

[18] Note that COM-002-2a and COM-002-3, which are Pending Regulatory Filing, will be replaced by COM-002-4.

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, the applicability of FAC-001 does not need to be changed for dispersed power producing resources.*

Commented [SC3]: SMC to reach out to IVGTF.

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 generation 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 generation 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 the corresponding RSAW, and as follows:*

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

[19] http://www.nerc.com/files/2012_IVGTF_Task_1-3.pdf

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:

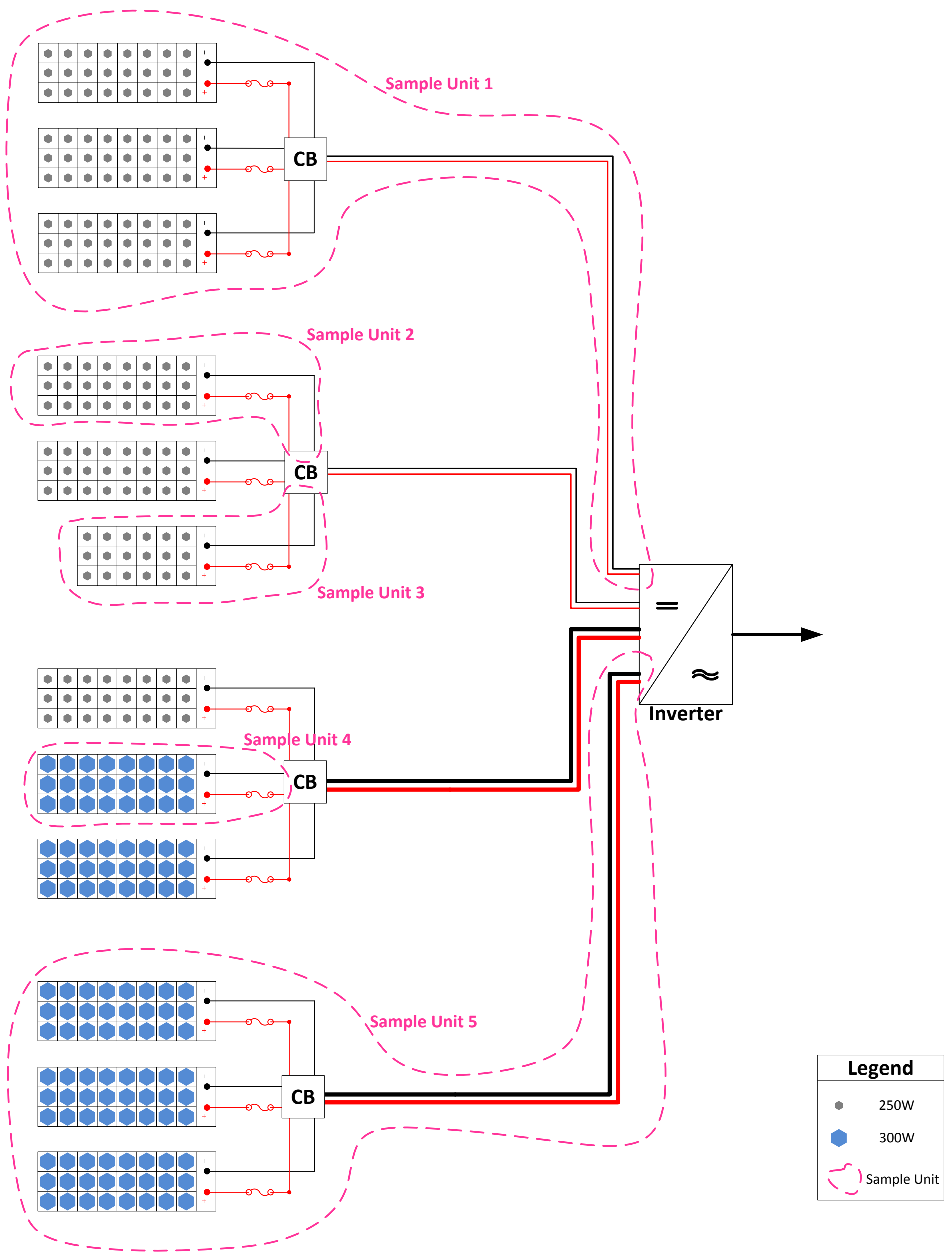
1. Referencing the NERC Glossary definition of Facility Ratings, identifies that the voltage, current, frequency, real or reactive power flow through a facility must not violate the equipment rating of any equipment of the facility (which is subjected to the voltage, current, etc.). With this definition, 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.

2. 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	Multiplier
15-module String	100
Fuses	100
Positive/Negative DC Cables	200
Combiner Box	20
Inverter	20
Transformer	1

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 generation resources.*

4.6 IRO

Commented [SC4]: IRO sub team to review and report to SDT.

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[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 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

[20] 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.

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.*

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 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 generation 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 generation resources. However, due to the unique nature of dispersed 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 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.*

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.*

[21] 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.

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.*

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.*

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 will recommend revisions to 4.2.3 to align the language with the revised BES definition.*

Commented [SC5]: MOD sub team to explain why no changes were made in the Facilities sections.

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, the SDT recommends clarifying the applicability to ensure the Facilities section aligns with dispersed generation resources.*

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. *However, the SDT recommends clarifying the applicability to ensure the Facilities section aligns with dispersed generation resources.*

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

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 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 generation resources. Such guidance should require modeling requirements for each type of dispersed generation 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 generation resources.*

Commented [SC6]: The sub team may make a recommendation for SDT consideration.

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 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 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 generation resources from any other GOP resources. *Therefore, the applicability of the PER standards do not need to be changed for dispersed generation resources.*

4.10 PRC

Commented [SC7]: Sub team to ensure that standard modifications are accurately reflected here.

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 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 andthe 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 SDT has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.

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. 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 withdrawn when the currently proposed versions of the TOP and IRO Reliability Standards included in Project 2014-3 are filed at FERC. *For this reason, no changes are required.*

Commented [SC8]: PRC sub team to review language.

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 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.*[23]

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 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 (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 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 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 that it is not necessary under PRC-004 to analyze each individual Protection System Misoperation affecting individual generating units of a dispersed generation resource, but is concerned

[23] *See* NPCC CGS-005.

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 resource site, only for events affecting greater than 75MVA aggregate nameplate; the SDT feels this will ensure that common mode failure scenarios and their potential impact on BPS reliability are appropriately addressed*.

4.10.5 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.*

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 applicability of this standard does not need to be changed for dispersed generation resources, as guidance has been provided in the form of recommended changes to the RSAW.*

4.10.7 PRC-005-2— Protection System Maintenance
PRC-005-3 — Protection System and Automatic Reclosing Maintenance
PRC-005-x — 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; 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

[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.

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 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 -X to indicate that maintenance activities should only apply on the aggregating equipment at or above the point where the aggregation exceeds 75 MVA.*

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 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.*

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 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 resources.*

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

Dispersed generation 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 SDT has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to this standard's requirements.*

4.10.11 PRC-023— Transmission Relay Loadability

Dispersed generation 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 generation 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. The BES definition changes have no direct impact on the applicability of this standard to dispersed generation resources. *Therefore, the applicability of these standards does not need to be changed for dispersed generation resources.*

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

Commented [SC9]: Sub team to review and revise language.

If the individual generating units at a dispersed generation resource were excluded from this requirement, it is possible large portions or perhaps the entire output of a dispersed generation 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 addressing the scope of applicability as stated above and will recommend changes to the RSAW to address documentation options.*

4.10.13 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. The SDT has determined it is appropriate to require that Protection System settings applied on both the individual generating units at a dispersed generation 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. *No changes to the standard are required; however, the SDT is recommending changes to the RSAW to clarify compliance evidence requirements.*

4.11 TOP

Commented [SC10]: Sub team to review and advise.

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 generation 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 generation 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 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 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 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.*

Commented [SC11]: Awaiting TOP SDT draft to finalize.

4.11.2 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.*

Commented [SC12]: Awaiting TOP SDT draft to finalize.

4.11.3 TOP-002-2.1b — Normal Operations Planning[25]

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 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.

[25] 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.

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[26]

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 resource aggregated facility level and as in such, feels 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 generation 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

[26] 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.

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.*

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 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.*

Commented [SC13]: Revise if necessary after review.

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, 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-02-3 R4 for dispersed power producing resources.*

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.*

4.14 CIP

4.14.1 CIP v5

Commented [SC14]: Sub team to consider how applicability would look in CIP v2 or v3.

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 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. 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, 2014

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Table of Contents

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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 Power Producing 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, 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 (relevant versions)[4];
- PRC-005 (relevant versions)[5]; and
- VAR-002 (relevant versions)[6].

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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 is currently being revised as part of Project 2010-05.1 Protection Systems: Misoperations.
[5] Reliability Standard PRC-005 is currently being revised as part of Project 2007-17.3 – Protection System Maintenance and Testing – Phase 3.
[6] Reliability Standard VAR-002 is currently being revised as part of Project 2013-04 – Voltage and Reactive Control.

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However, the SDT has recognized that many 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 BES definition. The proposed resolutions target the applicability of the standard noted in the language of the applicability section or specifically target 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 effort.

The technical section of this paper includes insight from the SDT review, including the history of standards applicability to dispersed power producing 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.

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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[8] 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.[9] 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 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.
[9] *North American Electric Reliability Corporation*, 138 FERC ¶ 61,193 at P 81 (2012).

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3 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'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 Adequate Level of Reliability for the reliability of the interconnected BPS.

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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,[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 providing an alternative to, or an enhancement of, the traditional electric power*

[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.

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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

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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]

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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 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

[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).

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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 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.[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 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 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 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

[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

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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, 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 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 July 2, 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.

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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 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.

3.3.3 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 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.

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- 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.

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.

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 generation 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 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.*

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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 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 resources.*

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Commented [SC2]: Tony to review COM-002-4.

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 generation resources from any other GO and/or GOP resource and determined that no changes are required to the standard.*

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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 generation 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 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

[18] Note that COM-002-2a and COM-002-3, which are Pending Regulatory Filing, will be replaced by COM-002-4.

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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, the applicability of FAC-001 does not need to be changed for dispersed power producing resources.*

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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 generation 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 generation 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 the corresponding RSAW, and as follows:*

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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

[19] http://www.nerc.com/files/2012_IVGTF_Task_1-3.pdf

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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:

1. 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.

2. 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).

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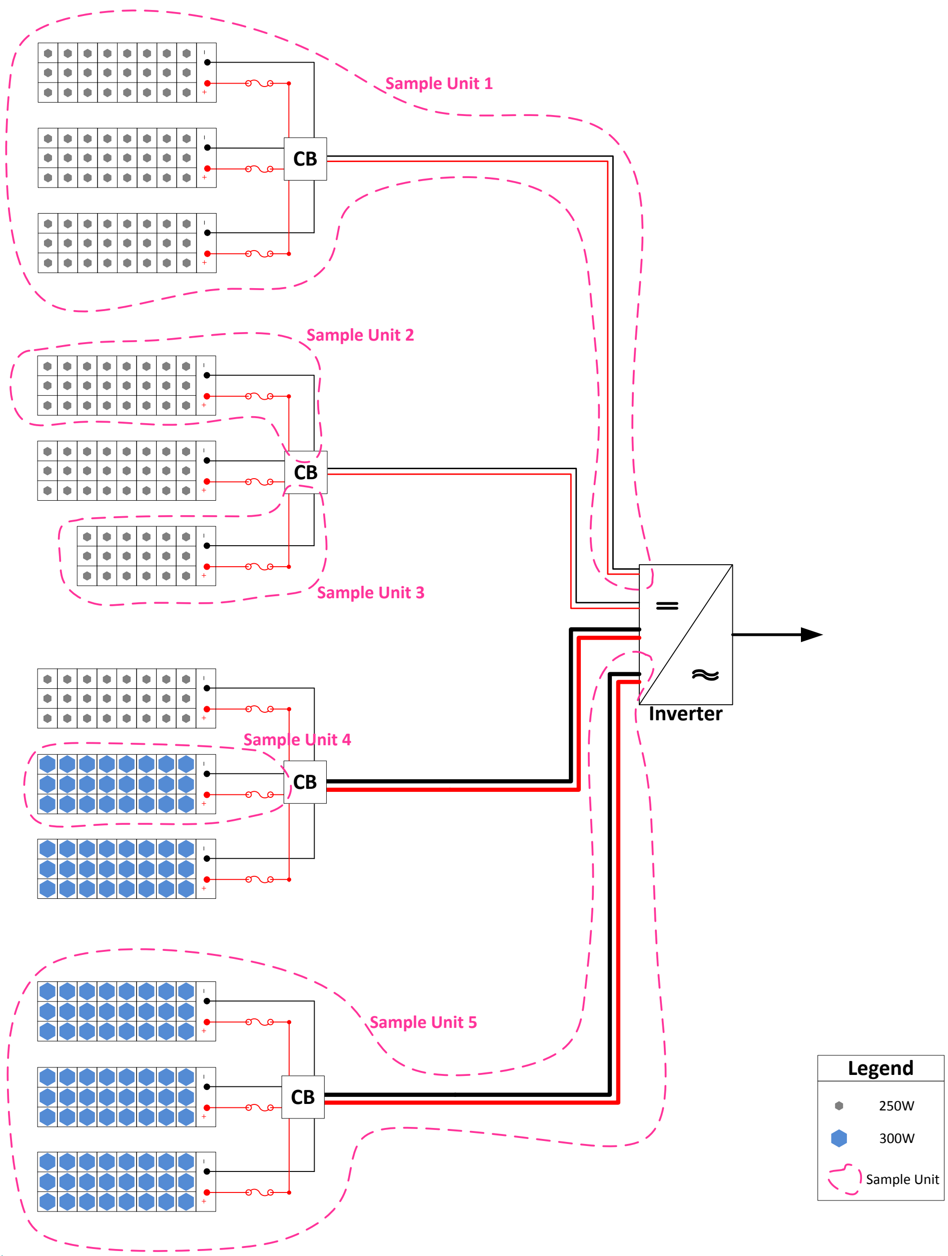

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Once a complete analysis of the sample unit is completed, this sample unit can then be referred to in future rating analysis without repeating the complete sample unit analysis.

Element	Multiplier
15-module String	100
Fuses	100
Positive/Negative DC Cables	200
Combiner Box	20
Inverter	20
Transformer	1

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 generation resources.*

4.6 IRO

Commented [SC4]: IRO sub team to review and report to SDT.

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[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 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

[20] 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.

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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.*

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 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 generation 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 generation resources. However, due to the unique nature of dispersed 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 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.*

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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.*

[21] 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.

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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.*

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.*

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 will recommend revisions to 4.2.3 to align the language with the revised BES definition.*

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Commented [SC5]: MOD sub team to explain why no changes were made in the Facilities sections.

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, the SDT recommends clarifying the applicability to ensure the Facilities section aligns with dispersed generation resources.*

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. *However, the SDT recommends clarifying the applicability to ensure the Facilities section aligns with dispersed generation resources.*

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

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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 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 generation resources. Such guidance should require modeling requirements for each type of dispersed generation 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 generation resources.*

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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 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 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 generation resources from any other GOP resources. *Therefore, the applicability of the PER standards do not need to be changed for dispersed generation resources.*

4.10 PRC

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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

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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 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 SDT has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.

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. 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 withdrawn when the currently proposed versions of the TOP and IRO Reliability Standards included in Project 2014-3 are filed at FERC. *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 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

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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.*[23]

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 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 (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 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 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 that it is not necessary under PRC-004 to analyze each individual Protection System Misoperation affecting individual generating units of a dispersed generation resource, but is concerned

[23] *See* NPCC CGS-005.

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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 resource site, only for events affecting greater than 75MVA aggregate nameplate; the SDT feels this will ensure that common mode failure scenarios and their potential impact on BPS reliability are appropriately addressed.*

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4.10.5 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.*

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 applicability of this standard does not need to be changed for dispersed generation resources, as guidance has been provided in the form of recommended changes to the RSAW.*

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4.10.7 PRC-005-2— Protection System Maintenance
PRC-005-3 — Protection System and Automatic Reclosing Maintenance
PRC-005-x — 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; 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

[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.

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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 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 -X to indicate that maintenance activities should only apply on the aggregating equipment at or above the point where the aggregation exceeds 75 MVA.*

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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 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

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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.*

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 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 resources.*

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

Dispersed generation 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 SDT has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to this standard's requirements.*

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4.10.11 PRC-023— Transmission Relay Loadability

Dispersed generation 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 generation 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. The BES definition changes have no direct impact on the applicability of this standard to dispersed generation resources. *Therefore, the applicability of these standards does not need to be changed for dispersed generation resources.*

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

If the individual generating units at a dispersed generation resource were excluded from this requirement, it is possible large portions or perhaps the entire output of a dispersed generation 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 addressing the scope of applicability as stated above and will recommend changes to the RSAW to address documentation options*.

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4.10.13 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. The SDT has determined it is appropriate to require that Protection System settings applied on both the individual generating units at a dispersed generation 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. *No changes to the standard are required; however, the SDT is recommending changes to the RSAW to clarify compliance evidence requirements.*

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4.11 TOP

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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.

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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 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 generation 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 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 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 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.*

Commented [SC11]: Awaiting TOP SDT draft to finalize.

4.11.2 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

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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.*

Commented [SC12]: Awaiting TOP SDT draft to finalize.

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 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 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.

[26] 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.

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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.*

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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.

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 resource aggregated facility level and as in such, feels 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 generation 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

[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.

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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.*

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 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.*

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.

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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, 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-02-3 R4 for dispersed power producing resources.*

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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

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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.*

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4.14 CIP

4.14.1 CIP v5

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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 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. 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

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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.

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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.*

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Appendix A: List of Standards

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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-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	Yes	
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-003-3	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-2	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-026-1	Subject to Enforcement	Yes	
MOD-027-1	Subject to Enforcement	Yes	
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-1a	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	YES - WECC
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-002-WECC-02	Subject to Future Enforcement	No	YES
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	
EOP-010-1	Subject to Future Enforcement	No	
MOD-025-2	Subject to Future Enforcement	Yes	
MOD-032-1	Subject to Future Enforcement	Yes	
MOD-033-1	Subject to Future Enforcement	No	
PER-005-2	Subject to Future Enforcement	No	
PRC-005-2	Subject to Future Enforcement	Yes	
PRC-006-NPCC-1	Subject to Future Enforcement	Yes	YES
PRC-019-1	Subject to Future Enforcement	Yes	
PRC-024-1	Subject to Future Enforcement	Yes	
TPL-001-4	Subject to Future Enforcement	No	
Standard Number	Pending Regulatory Approval	Further Review by SDT	
BAL-001-2	Pending Regulatory Approval	No	
BAL-002-1a	Pending Regulatory Approval	No	
COM-001-2	Pending Regulatory Approval	No	
COM-002-4	Pending Regulatory Approval	No	
CIP-014-1	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	
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-031-1	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-006-3	Pending Regulatory Approval	Yes
VAR-001-4	Pending Regulatory Approval	No
VAR-002-3	Pending Regulatory Approval	Yes
Standard Number	Pending Regulatory Filing	Further Review by SDT
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
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	*See Project 2014-03	Yes
IRO-002-3	*See Project 2014-03	No
IRO-005-4	*See Project 2014-03	Yes
IRO-014-2	*See Project 2014-03	No
PRC-001-2	*See Project 2014-03	Yes
TOP-001-2	*See Project 2014-03	Yes
TOP-002-3	*See Project 2014-03	Yes
TOP-003-2	*See Project 2014-03	Yes

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**

HIGH PRIORITY		
Standard Number	Area To Change	Target Applicability
PRC-004-2.1a	Applicability Section	Misoperations affecting >75MVA
PRC-004-3	Applicability Section	Misoperations affecting >75MVA
PRC-005-2	Applicability Section	Point where aggregates to >75MVA
PRC-005-3	Applicability Section	Point where aggregates to >75MVA
PRC-005-X	Applicability Section	Point where aggregates to >75MVA
VAR-002-2b	Applicability Section & Footnote	Aggregate Facility Level for Voltage Control; Transmission voltage GSUs
VAR-002-3	Applicability Section & Footnote	Aggregate Facility Level for Voltage Control; Transmission voltage GSUs
MEDIUM PRIORITY		
Standard Number	Area To Change	Target Applicability
EOP-004-2	No Action	NA
FAC-008-3	Guidance	Individual BES Resources /Elements to Include Aggregating Equipment
MOD-025-2	No Action	NA
MOD-026-1	No Action	NA
MOD-027-1	No Action	NA
MOD-032-1	No Action	NA
PRC-001-1.1	Applicability Section	Aggregate Facility Level
PRC-019-1	Applicability Section	Individual BES Resources/Elements
PRC-024-1	By Requirement	Individual BES Resources /Elements to Include Aggregating Equipment
PRC-025-1	Guidance	Individual BES Resources /Elements to Include Aggregating Equipment
TOP-001-1a	No Action	NA
TOP-002-2.1b	Applicability Section	Aggregate Facility Level
TOP-003-1	By Requirement	Aggregate Facility Level
TOP-006-2	No Action	NA
LOW PRIORITY		
Standard Number	Area To Change	Target Applicability
BAL-001-TRE-1	Applicability Section	Aggregate Facility Level
PRC-004-WECC-1	Applicability Section	Point where aggregates to >75MVA
PRC-006-NPCC-1	By Requirement	Individual BES Resources/Elements
PRC-006-SERC-01	By Requirement	Individual BES Resources/Elements

Project 2014-01 Standards Applicability for Dispersed Generation Resources – Outreach Efforts

Date	Forum	Group / Event	Performed by	Notes
COMPLETED				
January 2014	CC	Direct Outreach	Sean Cavote	Sean discussed the project with prospective SDT members and interested observers to explain project goals and objectives, and to solicit participation.
April 2, 2014	In-person	NERC Standards and Compliance Workshop	Tony Jankowski, Sean Cavote	Tony delivered a PowerPoint presentation on the DGR project and draft White Paper.
April 28, 2014	Webinar	DGR Industry Webinar	Tony Jankowski, Sean Cavote	Tony conducted a webinar to explain draft White Paper and to elicit industry feedback.
May 7, 2014	In-person	NERC Board of Trustees Meeting	Brian Evans-Mongeon	Brian discussed the project with interested observers.
May 29, 2014	In-person	NPCC Workshop	Rob Robertson	Rob delivered a PowerPoint presentation and provided information on the DGR project and draft White Paper.
May 2014	CC	Direct Outreach	Jeff Plew	Jeff discussed White Paper comments on PRC-005 with commenters to ensure SDT response addresses specific concerns.
June 9, 2014	CC	Teleconference	Ryan Stewart	Discussion among the CIP co-chairs, NERC, and members of the DGR SDT to discuss project objectives and coordinated guidance.
June 10, 2014	In-person	NERC PMOS / Standards Committee Meetings	Laura Hussey	Laura delivered a PowerPoint presentation on NERC's posting and version strategy on DGR applicability changes to PRC-005 and VAR-002.
June 10, 2014	In-person	NERC PMOS / Standards Committee Meetings	Sean Cavote	Sean provided information on the DGR project with various SC members and observers.
June 10, 2014	In-person	NERC Planning Committee Meeting	Brian Evans-Mongeon	Brian delivered a presentation on the DGR project.

Project 2014-01 Standards Applicability for Dispersed Generation Resources – Outreach Efforts				
June 18, 2014	In-person	NPCC Compliance Committee	Rob Robertson	Rob delivered a PowerPoint presentation and provided information on the DGR project and draft White Paper.
June 24, 2014		MISO Reliability Subcommittee	Tony Jankowski	Tony provided an update.
June 26, 2014	Newsletter	NERC News	Sean Cavote	Short DGR article published in NERC's Monthly Newsletter (June 2014).
Ongoing	Internal Outreach	NERC	Sean Cavote, Ryan Stewart	Coordinate with Scott Barfield (PRC-004), Soo Jin Kim (VAR-002), and Jordan Mallory (PRC-005) on concurrent projects.
Ongoing	CC	NPCC Regional Standards Committee	Sean Cavote, Ryan Stewart	Discuss status of project.
July 7, 2014	In-Person	NERC Reliability Standards Subcommittee of the Texas RE	Dana Showalter	Dana will provide updates.
July 9, 2014 1:00 p.m. to 4:00 p.m. CT	CC	SPP Standards Review Group	George Brown	George and Sean participated.
July 10, 2014		RF Reliability Committee	Tony Jankowski	Tony provided a DGR update.
July 15, 2014 3:00 CT	CC	Wind Coalition (ERCOT- and SPP-focused advocacy group)	Dana Showalter	Dana will provide an update.
July 15, 2014	Webinar	DGR Industry Webinar	Tony Jankowski Sean Cavote	SDT webinar to explain high-priority DGR applicability changes and to elicit industry feedback (PRC-004, PRC-005, and VAR-002).
July 22, 2014	CC	Wind Coalition Ops call	Dana Showalter	Dana presented.
July 29-30, 2014	CC	WECC PRC-005 Workshop	TBD	Contacts: Phil O'Donnel. Sean and Jordan have reached out to WECC.
August 6, 2014	CC	North American Generator Forum (NAGF) Standard Review Team Meeting	George Brown	George delivered a PowerPoint presentation.

Project 2014-01 Standards Applicability for Dispersed Generation Resources – Outreach Efforts				
August 18, 2014 1:00 p.m. to 2:00 p.m. CT	CC	RFC Monthly Open Compliance Call (third Monday of every month)	George Brown	George provided an update.
August 19, 2014	In-Person	NRWG at ERCOT	Dana Showalter	Dana presented.
August 2014	CC	Western Interconnection Compliance Forum (monthly call)	Jessie Nevarez	Jessie provided an update.
October 7-9, 2014	In-person	North American Generator Forum (NAGF) Annual Meeting	Sean Cavote Dana Showalter	Dana reached out to NAGF.
PLANNED				
October 20, 2014 1:00 p.m. to 2:00 p.m. CT	CC	RFC Monthly Open Compliance Call (third Monday of every month)	George Brown	George will provide an update.
October 22, 2014	Electronic	RF electronic message	George Brown	George provided electronic documents as an update
November 19, 2014	In-person and CC	Fall 2014 NPCC Compliance and Standards Workshop	Rob Robertson	Rob will provide an update
Ongoing	CC	MRO NSRF (every Wednesday)	George Brown	George will provide an update.
Every other Tuesday	CC	North American Generator Forum (NAGF) Advisory Committee	Dana Showalter Dave Belanger	Dana and Dave will provide updates.
Ongoing	CC	NERC Reliability Standards Subcommittee of the Texas RE	Dana Showalter	Dana will provide updates.
Ongoing	In-person and CC	ERCOT NERC Reliability Working Group (NRWG)	Dana Showalter	Dana will provide updates.
POTENTIAL OPPORTUNITIES				

NERC

Project 2014-01 Standards Applicability for Dispersed Generation Resources – Outreach Efforts				
		Wind on the Wires		
		MAREC		
Ongoing	Weekly Newsletter	AWEA	Rob Robertson Dana Showalter	
Ongoing	CC	SERC Registered Entities Forum	Dana Showalter	Dana is reaching out to that organization.
November 19-20, 2014	In-Person	AWEA Fall Symposium	TBD	Rob Robertson and Sean Cavote are reaching out to AWEA.
		IESO Ontario Reliability Compliance Program		George Brown is reaching out to NAGF.
Regularly Scheduled	In-person or CC	ISO/RTO Standards Review Committee (SRC)	TBD	Contact is Greg Campoli (gcampoli@nyiso.com).
Beginning of every month	In-person and CC	FRCC PC and OC	TBD	Jeff Plew can find out contacts and upcoming dates.
Regularly Scheduled	Webinar, CC, etc.	ERCOT Standard, Compliance, and Registration Group	TBD	
Every Wednesday	CC	MRO NERC Standards Review Forum	TBD	Contact: Joe DePoorter (jdepoorter@MGE.com)
Every other Monday	CC	TRE NERC Standards Review Subcommittee	TBD	(don.jones@texasre.org)
Bi-weekly	Webinar	North American Generator Forum (NAGF) Standards Review Team	TBD	Contact: Patrick Brown (patrick.brown@essentialpowerllc.com)
2nd Friday of every month	CC	Canadian Electric Association (CEA) Regulatory Development Task Group (RDTG)	TBD	Contact: Patrick Brown (brown@electricity.ca)
3rd Thursday of every month	CC	WECC Open Mic Call	TBD	Contact: Laura Scholl (lscholl@wecc.biz)

Project 2014-01 Standards Applicability for Dispersed Generation Resources – Outreach Efforts				
Monthly CC and two annual meetings	CC	North American Transmission Forum (NATF)	TBD	
Regularly scheduled	CC	American Public Power Association (APPA)	TBD	Contact: Allen Mosher (amosher@publicpower.org); Nathan Mitchell (nmitchell@publicpower.org)
Regularly scheduled	CC	Electricity Consumers Resource Council (ELCON)	TBD	Contact: John Anderson (janderson@elcon.org); John Hughes (jhughes@elcon.org)
Regularly scheduled	CC	Electric Power Supply Association (EPSA)	TBD	Contact: Jack Cashin (jcashin@epsa.org)
Regularly scheduled	CC	Large Public Power Council (LPPC)	TBD	Contact: Johnathan Schneider (jschneider@stinson.com)
Regularly scheduled	CC	Mid-Continent Compliance Forum	TBD	Contact: Randi Nyholm (rnyholm@mnpower.com)
Regularly scheduled	CC	MRO Standards Committee	TBD	Contact: Jennifer Matz (jl.matz@midwestreliability.org)
Regularly scheduled	CC	National Association of Regulatory Utility Commissioners (NARUC) Staff Committee on Electric Reliability	TBD	Contact: Diane Barney (Diane.Barney@dps.ny.gov)
Regularly scheduled	CC	National Rural Electric Cooperative Association (NRECA)	TBD	Contact: Barry Lawson (barry.lawson@nreca.coop)
Regularly scheduled	CC	Transmission Access Policy Study Group (TAPS)	TBD	Contact: Bill Gallagher (bgallagher@vppsa.com)
Set event	In-person meeting	Canadian Electricity Association's (CEA) T-Council Meeting	TBD	Contact: Patrick Brown (brown@electricity.ca)

Project 2014-01 Standards Applicability for Dispersed Generation Resources – Outreach Efforts				
Set event	In-person meeting	NERC Trades Meeting	TBD	Contact: Kristin Iwanechko
Set event	In-person meeting	SPP Compliance Workshop	TBD	Contact: Kim Van Brimer (kvanbrimer@spp.org); Emily Pennel (epennel.re@spp.org);
Set event	In-person meeting	TRE Reliability Standards Committee (RSC)	TBD	Contact: Don Jones (don.jones@texasre.org)
Set event	In-person meeting	FRCC Compliance Workshop	TBD	Contact: Linda Campbell (lcampbell@frcc.com)
Set event	In-person meeting	TRE Fall Workshop	TBD	Contact: Sarah Hensley (sarah.hensley@texasre.org); Jaycee Rivas (jaycee.rivas@texasre.org)
Set event	In-person meeting	SERC Compliance Workshop	TBD	Contact: Linda Peavy (lpeavy@serc1.org)
Set event	In-person meeting	Canadian Electricity Association's (CEA) Regulatory Development Task Group (RDTG)	TBD	Contact: Patrick Brown (brown@electricity.ca)
Set event	In-person meeting	MRO Compliance Workshop	TBD	Contact: Jennifer Matz (jl.matz@midwestreliability.org)
Set event	In-person meeting	NPCC Regional Standards Committee (RSC)	TBD	Contact: Guy Zito (gzito@npcc.org)

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Team Roster

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

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