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

**North American Electric Reliability
Corporation**

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Docket No. _____

**PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARD PRC-005-3
(PROTECTION SYSTEM MAINTENANCE)**

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February 14, 2014

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Pursuant to Section 215(d)(1) of the Federal Power Act (“FPA”)¹ and Section 39.5² of the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) regulations, the North American Electric Reliability Corporation (“NERC”)³ hereby submits for Commission approval:

- proposed Reliability Standard PRC-005-3 (Protection System Maintenance) (**Exhibit A**);
- one new (Automatic Reclosing) and five revised definitions (Unresolved Maintenance Issue, Segment, Component Type, Component, and Countable Event)⁴;
- the implementation plan for proposed Reliability Standard PRC-005-3 (“Implementation Plan”) (**Exhibit B**); and
- the Violation Risk Factors (“VRFs”) and the revised Violation Severity Levels (“VSLs”) for proposed PRC-005-3 (**Exhibit A and Exhibit G**).

¹ 16 U.S.C. § 824o (2012).

² 18 C.F.R. § 39.5 (2014).

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

⁴ These terms were approved as PRC-005 specific definitions along with the approval of Reliability Standard PRC-005-2. *See Protection System Maintenance Reliability Standard*, Order No. 793, 145 FERC ¶ 61,253 (2013). The definitions can be found in the posted PRC-005-2 Reliability Standard. Once approved, the revised versions of the definitions will located in the posted version of proposed PRC-005-3.

NERC requests that the Commission approve the proposed Reliability Standard and find that it is just, reasonable, not unduly discriminatory or preferential, and in the public interest.⁵ NERC also requests approval of the retirement of Reliability Standard PRC-005-2⁶ as detailed in the Implementation Plan.

As required by Section 39.5(a)⁷ of the Commission’s regulations, this petition presents the technical basis and purpose of proposed Reliability Standard PRC-005-3, a summary of the development history (**Exhibit H**), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672⁸ (**Exhibit C**). Proposed Reliability Standard PRC-005-3 was approved by the NERC Board of Trustees on November 7, 2013.

I. EXECUTIVE SUMMARY

In Order No. 758, the Commission directed NERC to include maintenance and testing of reclosing relays that can affect the Reliable Operation of the Bulk-Power System in Reliability Standard PRC-005. Reclosing relays are applied to facilitate automatic restoration of system components following a Protection System operation.⁹ In certain circumstances the misoperation of reclosing relays can impact the reliability of the Bulk-Power System.

⁵ Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, available at http://www.nerc.com/files/Glossary_of_Terms.pdf

⁶ Reliability Standard PRC-005-2 was approved by the Commission on December 19, 2013. *See* Order No. 793, 145 FERC ¶ 61,253.

⁷ 18 C.F.R. § 39.5(a) (2013).

⁸ The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh’g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

⁹ As reclosing relays facilitate automatic restoration, they are often referred to as “automatic reclosing relays” or “autoreclosing relays”. The term “reclosing relay”, as used in this Petition, has the same meaning as the terms “automatic reclosing relay” and “autoreclosing relay” as they may appear in Exhibits to this Petition.

In response to Order No. 758, the NERC System Analysis and Modeling Subcommittee (“SAMS”) and System Protection and Control Subcommittee (“SPCS”) jointly performed a technical study to determine which reclosing relays should be addressed within PRC-005 and provide advice to the Protection System Maintenance and Testing Standard Drafting Team (“Standard Drafting Team”) regarding appropriate maintenance intervals and activities for those relays (“SAMS/SPCS Report”) (**Exhibit D**). The Standard Drafting Team developed revisions to Reliability Standard PRC-005-2 in line with the SAMS/SPCS Report recommendations. As a result, proposed Reliability Standard PRC-005-3 adds reclosing relays that can affect the reliable operation of the Bulk-Power System to the applicability of Reliability Standard PRC-005 to satisfy NERC’s commitment to address the Order No. 758 directive and provide for the maintenance and testing of these relays.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:¹⁰

¹⁰ Persons to be included on the Commission’s service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission’s regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,¹¹ Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation’s Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)¹² of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)¹³ of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)¹⁴ of the Commission’s regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become

¹¹ 16 U.S.C. § 824o (2012).

¹² *Id.* § 824(b)(1).

¹³ *Id.* § 824o(d)(5).

¹⁴ 18 C.F.R. § 39.5(a).

mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA¹⁵ and Section 39.5(c)¹⁶ of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.¹⁷ NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.¹⁸ In its order certifying NERC as the Commission's Electric Reliability Organization, , the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards¹⁹

¹⁵ 16 U.S.C. § 824o(d)(2).

¹⁶ 18 C.F.R. § 39.5(c)(1).

¹⁷ *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

¹⁸ The NERC *Rules of Procedure* are available at <http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>. The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

¹⁹ 116 FERC ¶ 61,062 at P 250.

and thus satisfies certain of the criteria for approving Reliability Standards.²⁰ The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. History of Project 2007-17.2

In Order No. 693,²¹ the Commission approved Reliability Standard PRC-005-1 and directed NERC to “develop a modification ... through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.”²² In 2007, NERC initiated Project 2007-17 Protection System Maintenance and Testing to address the Commission’s directive.

While the Standard Drafting Team developed these revisions to PRC-005, the Commission approved two interpretations of PRC-005-1. On April 15, 2011, NERC filed a petition seeking Commission approval of an interpretation of Requirements R1 and R3 of Reliability Standard PRC-004-1 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) and Requirements R1 and R2 of Reliability Standard PRC-005-1 (Transmission and Generation Protection System Maintenance and Testing). The Commission approved NERC’s interpretation, effective as of September 26, 2011.²³ On

²⁰ Order No. 672 at PP 268, 270.

²¹ *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (“Order No. 693”), *order on reh’g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

²² *Id.* at P 1475.

²³ *N. Am. Elec. Reliability Corp.*, 136 FERC 61,208 (2011).

February 3, 2012, the Commission issued Order No. 758,²⁴ approving a second interpretation of PRC-005-1. In that Order, the Commission directed NERC to address concerns raised regarding reclosing relays in the revisions to Reliability Standard PRC-005-1. Specifically, the Commission directed NERC to include maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System.²⁵

In response to Order No. 758, the Standard Drafting Team drafted a Standard Authorization Request to modify PRC-005 to include the maintenance and testing of reclosing relays that can affect the Reliable Operation of the Bulk-Power System. On May 10, 2012, the NERC Standards Committee accepted the Standard Authorization Request and authorized that it be posted for information only along with the third draft of PRC-005-2.

On July 30, 2012, NERC submitted an informational filing²⁶ reporting to the Commission that proposed Reliability Standard PRC-005-2—containing the revisions to Reliability Standard PRC-005-1 outlined in Order No. 693—was in the final stages of development and that NERC would address the Commission’s directive regarding reclosing relays in a separate petition. On January 17, 2013, the NERC Standards Committee approved a Standard Authorization Request to address the addition of reclosing relays through Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays).

IV. JUSTIFICATION FOR APPROVAL

As discussed in **Exhibit C** and below, proposed Reliability Standard PRC-005-3 satisfies the Commission’s criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or

²⁴ *Interpretation of Protection System Reliability Standard*, Order No. 758, 138 FERC ¶ 61,094 (“Order No. 758”), *order on reh’g*, 139 FERC ¶ 61,227 (2012).

²⁵ *Id.* at P 22-27.

²⁶ *NERC Jul. 30, 2012 Informational Filing in Compliance with Order No. 758*, Docket No. RM10-5 (2012), available at: http://www.nerc.com/pa/Stand/Project%202007172%20Protection%20System%20Manintenance%20and/Final_Info_Filing_Order_758_07-30-12_complete.pdf.

preferential, and in the public interest. The improved proposed Reliability Standard promotes reliability by adding Automatic Reclosing to the Commission-approved Reliability Standard PRC-005-2. The purpose of proposed PRC-005-3 is to document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System so that they are kept in working order.

PRC-005-3 has five Requirements that address the inclusion of Automatic Reclosing. The revised Reliability Standard requires entities to develop an appropriate Protection System Maintenance Program, to implement their program, and to initiate the follow-up activities necessary to resolve maintenance issues in the event they are unable to restore Automatic Reclosing Components to proper working order while performing maintenance. Proposed PRC-005-3 adds detailed tables of minimum maintenance activities and maximum maintenance intervals for Automatic Reclosing to the existing PRC-005-2 Reliability Standard, extending the benefits of a strong maintenance program to these Components. The subset of Automatic Reclosing applications included in proposed PRC-005-3 is based on the findings of the SAMS/SPCS Report included as **Exhibit D**. To assist responsible entities in understanding the addition of Automatic Reclosing to PRC-005, the Standard Drafting Team revised the *Supplementary Reference and FAQ* document developed with PRC-005-2 and posted the document concurrently with the proposed Reliability Standard during each posting. This revised document will be posted with the proposed PRC-005-3 Reliability Standard following approval.

Proposed PRC-005-3 satisfies the Commission's directive in Order No. 758 by including the necessary reclosing relay applications with the potential to impact Reliable Operation of the Bulk-Power System in the scope of Reliability Standard PRC-005. Provided below is a summary of the recommendations from the SAMS/SPCS Report including discussion of

reclosing relays, an overview of the modifications to Reliability Standard PRC-005-2 necessary to meet the Commission’s directive, and a discussion of the Implementation Plan.

A. Reclosing Relays

Reclosing relays are utilized on transmission systems to restore transmission elements to service following automatic circuit breaker tripping.²⁷ There are several types of reclosing relays, including electromechanical, solid state, and microprocessor-based, which may be applied in a variety of scenarios.²⁸ Most reclosing relays share three main functions: supervisory, timing, and output.²⁹ A relay failure is most likely to occur as part of one of these functions. Reclosing relays are typically installed to lessen the burden on Transmission Operators of manually restoring transmission lines.³⁰ Relays of this type also provide improved capability in restoration of overhead transmission lines. The degree to which such capability is improved depends on the nature of the fault—permanent or temporary—and on Transmission Operator practices regarding manual restoration.³¹

While more efficient restoration of transmission lines following temporary faults does provide an inherent reliability benefit, certain applications of reclosing relays can result in undesired relay operation or operation not consistent with relay design, leading to adverse reliability impacts. Because certain applications of reclosing relays can have the potential to impact the Bulk-Power System, it is beneficial to reliability that those relays be included under the applicability of proposed Reliability Standard PRC-005-3.

B. SAMS/SPCS Report

²⁷ See SAMS/SPCS Report, Ex. D at 2.

²⁸ *Id.* at 3.

²⁹ *Id.* at 3-4.

³⁰ *Id.* at 3.

³¹ *Id.*

The SAMS/SPCS Report recommended that the Standard Drafting Team modify Reliability Standard PRC-005-2 to: 1) explicitly address maintenance and testing of reclosing relays applied as an integral part of a Special Protection System; and 2) include maintenance and testing of reclosing relays at or in proximity to generating plants at which the total installed capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area.³² For this second category, the SAMS/SPCS Report suggested to define “proximity” as substations one bus away if the substation is within 10 miles of the plant. The SAMS/SPCS Report also suggested including a provision to exclude reclosing relays “if the equipment owner can demonstrate to the Transmission Planner that a close-in three-phase fault for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of generation in the interconnection exceeding the largest unit within the Balancing Authority Area where the autoreclosing is applied.”³³ Finally, the SAMS/SPCS Report included recommendations for minimum maintenance activities and maximum intervals based on comparable activities and intervals included in Reliability Standard PRC-005-2.³⁴

To reach these recommendations, SAMS and SPCS considered the Commission’s concerns in Order No. 758 and summarized in the SAMS/SPCS Report that the Commission’s concerns could be grouped into two categories: (1) situations in which reclosing relays fail to operate when required to maintain Bulk-Power System reliability; and (2) situations in which reclosing relays operate in a manner not consistent with design, adversely affecting reliability of the Bulk-Power System. The SAMS/SPCS Report addresses these two categories of concern by

³² *Id.* at 10.

³³ *Id.*

³⁴ *Id.*

studying reclosing applications to improve Bulk-Power System performance and to aid in restoration.

In assessing the first category, SAMS and SPCS noted that while successful operation of reclosing relays will enhance reliability of the Bulk-Power System, reclosing into a permanent power system fault may adversely impact reliability. Because the potential for permanent power system faults exists for any application, it is not possible to depend on successful reclosing relay operation as a sole means to guarantee reliability or satisfy the Requirements contained in Reliability Standards. The same issues exist for single-pole reclosing with regard to the potential for reclosing into a permanent fault after all three poles are tripped. The exception is when reclosing relays are included as an integral part of a Special Protection System (“SPS”). In these applications, other functions of the SPS will operate to preserve reliability in the event that reclosing is unsuccessful; thus, failure of any part of the SPS may adversely impact reliability of the Bulk-Power System.

In assessing the second category, SAMS and SPCS note that reclosing relays are typically installed to alleviate the burden on operators of manually restoring transmission lines. Reclosing relays also provide improved availability of overhead transmission lines. The degree to which availability is improved depends on the nature of the fault (permanent or temporary) and on Transmission Operator practices for manually restoring lines. While faster restoration of transmission lines following temporary faults does provide an inherent reliability benefit, it is possible for undesired operation of the reclosing scheme, not consistent with its design, to adversely impact Bulk-Power System reliability. Certain credible failure modes, including those related to supervision, timing, and output, may lead to undesired reclosing relay operation which could pose a reliability risk.

C. Modifications in proposed Reliability Standard PRC-005-3

As discussed below, certain parts of Reliability Standard PRC-005-2 have been modified in order to add the necessary reclosing relays to the PRC-005 Reliability Standard.

1. Definitions

NERC developed one new and five revised definitions to accompany proposed PRC-005-3.³⁵ NERC proposes the following new definition to define the scope of what is included when Automatic Reclosing is referenced within the proposed PRC-005-3 Reliability Standard:

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

This definition is intended only for use within the proposed Reliability Standard and will not, at this time, be listed in the NERC Glossary of Terms.³⁶ The term will be included within the posted Reliability Standard itself.³⁷ This definition establishes that “Automatic Reclosing” includes reclosing relays and the associated dc control circuitry and reflects the SAMS/SPCS Report recommendation that PRC-005-3 should apply to both the reclosing relay and associated control circuitry. The recommendation includes both Component Types since a failure in the reclosing relay or the control circuitry may result in the same adverse reliability impact.

In addition, the previously-approved defined terms “Protection System Maintenance Program”, “Component Type”, “Component”, and “Countable Event” were revised to add the

³⁵ The definitions were posted in the draft PRC-005-3 Reliability Standard during the standards development process and will be implemented concurrently with the proposed Reliability Standard.

³⁶ NERC acknowledges the Commission’s statement in Order No. 793 that “NERC should not adopt inconsistent definitions for the same term.” Order No. 793 at P 70. Although this term will be posted along with the proposed Reliability Standard, NERC will not develop additional definitions of the same term approved for use in a particular Reliability Standard. If a future standards development project seeks to broaden the applicability of a standard-specific defined term, the defined term and where the term is posted (in the Reliability Standard or in the NERC *Glossary of Terms*) would need to be revisited through the standards development process.

³⁷ For clarity, NERC relocated the definitions specific to the PRC-005 Reliability Standard in part 6 of Section A (Introduction) in the posted version of the proposed Reliability Standard.

necessary reference to “Automatic Reclosing” or the associated Table within the proposed Reliability Standard to facilitate coverage of Automatic Reclosing Components within the coverage of the PRC-005 Requirements. The revised definitions are as follows (changes have been italicized for convenience):

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System *and Automatic Reclosing Components* are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Component Type – *Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.*

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

entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a *Protection System* Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or *Automatic Reclosing* configuration or application errors are not included in Countable Events.

Lastly, two definitions contain capitalization changes to the previously-approved definitions to correctly reference the defined term “Component.” The revised definitions read as follows:

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. Applicability

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing it outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in a new subsection 4.2.6 under the listing of covered “Facilities.” The PRC-005-3 *Supplementary Reference and FAQ* document includes examples to depict which Automatic Reclosing applications are included in the scope of the proposed PRC-005-3 Reliability Standard. The Applicability, as detailed below, was recommended by the NERC SAMS and

SPCS after a lengthy review of the use of reclosing within the Bulk Electric System. SAMS and SPCS concluded that reclosing is largely implemented throughout the Bulk Electric System as an operating convenience, and that reclosing mal-performance affects Bulk Electric System reliability only when the reclosing is part of a Special Protection System, or when premature reclosing has the potential to cause generating unit or plant instability.³⁸

a) Section 4.2.6.1

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.

The SAMS/SPCS Report assessed Automatic Reclosing failure modes for potential effects to Reliable Operation of the Bulk-Power System. The report identified that premature reclosing has the potential to cause generating unit or plant instability, and noted the impact on Reliable Operation when the loss of generating resources exceeds the largest unit³⁹ within the Balancing Authority Area in which the Automatic Reclosing is applied. In this context, the NERC Reliability Standards require consideration of loss of the largest generating unit within a Balancing Authority Area; therefore, generation loss would not impact reliability unless the combined capacity loss exceeds the largest unit within the Balancing Authority Area. Including maintenance and testing of reclosing relays in PRC-005 is, therefore, appropriate for applications of Automatic Reclosing at generating plants with capacity exceeding the largest unit within the Balancing Authority Area.

³⁸ See *Supplementary Reference and FAQ*, Ex.E at 7 (citing SAMS/SPCS Report).

³⁹ See *Supplementary Reference and FAQ*, Ex. E at 7. In this context the capacity of the largest unit is the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

The applicability includes a reference the Bulk Electric System (referred to in the applicability section as “BES”) in order to define the generating plant bus at which Automatic Reclosing is subject to PRC-005-3. In this context, “BES” is used to describe the high-voltage switchyard bus on the transmission system side of the generator step-up transformer. Similarly, “BES” is used to modify the largest generating unit with the Balancing Authority Area. Revisions to the “Bulk Electric System” definition are unlikely to affect present classification of generating units and buses in the context of the largest generating unit in a Balancing Authority Area or stations with capacity that exceed the largest unit within the Balancing Authority Area. However, PRC-005-3 will be workable regardless of how the Bulk Electric System is defined. If an element is a Bulk Electric System Element and is located at a generating plant substation, it is included per Section 4.2.6.1, and the Requirements for Automatic Reclosing apply.⁴⁰

b) Section 4.2.6.2

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.

Reclosing at transmission substations may affect the stability of generating units and generating plants when applied in proximity to a generating plant. Therefore, the Standard Drafting Team included applicability for Automatic Reclosing at buses in proximity to generating plants, in addition to Bulk Electric System buses at generating plants. The criteria that define proximity, i.e., “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,” originated from the SAMS/SPCS Report. The criteria are based on the collective experience of the

⁴⁰ See Section 2.4.1 in the *Supplementary Reference and FAQ* document, Ex. E, for additional discussion.

subcommittee members performing transient stability studies. Their experience reveals that for cases in which generating units exhibit an unstable response to a bus fault at the high-side of the generator step-up transformer, the units exhibit a stable response if the fault location is on the order of one mile from the bus. The difference in response is based on two factors. The first is the additional impedance between the generators and the fault. The second is that when there are additional sources of fault current in addition to the generator, the in-feed from the other sources makes the apparent impedance⁴¹ to the fault greater, further reducing the acceleration of the generating units during the fault. The SAMS and SPCS members applied a safety factor in recommending the 10-mile threshold.

c) Section 4.2.6.3

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

As noted in the SAMS/SPCS Report, Special Protection Systems may be applied to meet system performance requirements in the NERC Reliability Standards or to increase the transfer limit associated with an Interconnection Reliability Operating Limit. When reclosing is included as an integral part of such a SPS, a failure of the reclosing function may adversely impact Bulk-Power System reliability.⁴² In such applications, it typically is essential to successfully restore the power system to its pre-contingency state after a fault or disturbance (e.g., reclosing a transmission line connected at a generating station after it is tripped to clear a fault). Since it is possible that the fault or disturbance will be sustained and prevent restoration to the pre-contingency state, the SPS must take remedial action (e.g., initiating control system action or

⁴¹ Apparent impedance is a term that refers to the effective impedance when more than one source contributes current through an element, resulting in an effective impedance greater than the actual impedance of the element.

⁴² See SAMS/SPCS Report, Ex. E at 3.

tripping resources to reduce power transfers) if it determines the reclosing was unsuccessful. Unsuccessful reclosing may result from failure of the Automatic Reclosing or because of a subsequent trip when the fault or disturbance is sustained. In these applications Reliable Operation of the Bulk-Power System is dependent on proper operation of the SPS. This dependence on proper operation of the SPS dictates that maintenance and testing requirements apply to all parts of the SPS.

d) Footnote 1 Exclusion

FNI Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

The applicability for Automatic Reclosing in PRC-005-3 is based on the SAMS and SPCS assessment of failure modes of reclosing relays that could impact Reliable Operation of the Bulk-Power System. During the SAMS/SPCS study, the SPCS identified the worst case reclosing relay failure modes and SAMS assessed the reliability risk to the Bulk-Power System. The worst case failure mode identified by SPCS is a failure that would lead to reclosing with no time delay. SAMS identified that this failure mode presents a risk to Reliable Operation of the Bulk-Power System when reclosing relays are used at or in proximity to generating stations, because it could lead to generating unit instability. SAMS and SPCS concluded that maintenance and testing of Automatic Reclosing should be required when the potential loss of generating resources may exceed the gross capacity of the largest Bulk Electric System unit within the Balancing Authority Area where the Automatic Reclosing is applied. Thus, the applicability establishes a bright line to allow entities to assess which Automatic Reclosing is

subject to requirements in PRC-005-3. Further, SAMS and SPCS recognized that failure of Automatic Reclosing may not affect reliability of the Bulk-Power System at all locations identified in the applicability of PRC-005-3. Determining which, if any, locations identified in the applicability do not pose a reliability risk would require case-by-case studies of the worst-case failure mode on which the applicability is based. Rather than including a requirement in PRC-005-3 for entities to perform such analysis, the Standard Drafting Team included Footnote 1 to allow entities the option to instead rule out certain locations at which this risk is not present.

Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 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 Bulk Electric System unit within the Balancing Authority Area where the Automatic Reclosing is applied. This benchmark reflects the worst-case failure mode identified by SAMS and SPCS and, therefore, serves as a valid, technically-supported test for ruling out certain facilities from the applicability of PRC-005-3. The test simulates a fault for twice the normal clearing time because this is approximately the same as clearing the fault in normal clearing time, reclosing into the fault with no time delay, and clearing the fault again in normal clearing time.

e) NERC Evaluation of 10-Mile Threshold

As noted above, proposed Reliability Standard PRC-005-3 requires maintenance and testing of reclosing relays at generating stations, and at substations one bus away from a generating station if the substation is within 10 miles of the generating station. Further, the

criteria are based on the collective experience of the SAMS and SPCS members and include a safety factor in establishing the ten-mile threshold.

NERC staff has conducted an analysis to verify that the 10-mile threshold provides adequate margin to ensure maintenance and testing of all reclosing relays where failure could result in generating station instability. Testing was performed at the high-voltage switchyard for 50 generating stations. A sample of generating stations was used with high-side voltage ranging from 115 kV to 765 kV. The sample included a wide range of generating unit types, transmission line lengths, and switchyard configurations, and is therefore representative of generating stations across North America. Three-phase faults were simulated on each line⁴³ exiting each generating station. Faults were simulated for a duration that conservatively represents two times the normal clearing time for a three-phase fault. This test is based on a recommendation in the SAMS-SPCS Report to apply a close-in three-phase fault for twice the normal clearing time (capturing a minimum trip-close-trip time delay). This test approximates the response if a transmission line circuit breaker is reclosed into a fault without any time delay due to a reclosing relay failure. The fault durations used in the study are 8 cycles at voltage greater than 300 kV, 10 cycles for clearing times for voltage between 200 kV and 300 kV, and 12 cycles for voltage below 200 kV. Close-in faults were applied on each line on the line side of the circuit breaker(s). In cases where the generating unit response was unstable, the fault was reapplied at one-mile increments away from the bus until the generating unit response was stable. Testing was performed on a total of 145 transmission lines at 50 generating stations. The generating unit response was stable for 110 of the close-in faults. For the remaining 35 lines, the

⁴³ When two or more parallel lines exit a generating station and terminate at the same remote station, a fault was applied on only one line since the response would be essentially the same faults on each line.

generating response was stable for faults one mile from the generating station in 22 cases and was stable for faults greater than five miles from the generating station in 10 cases.

The three remaining cases involve two generating stations. At one station, the two transmission lines exiting the station are approximately 120 miles long. On one line, the generating units were stable for a fault 11 miles from the generating station and on the other line the generating units were unstable for faults anywhere on the line. At this generating station the predominant factor in the generating unit instability is the post-fault system impedance with the generating units remaining connected to one 120-mile line. The analysis was repeated at each remote bus at the remote terminal of the two 120-mile lines. The generating units were stable for close-in three phase faults on each line terminating at these remote buses. Since these remote buses are more than 10 miles from the generating station, PRC-005-3 would not be applicable to the reclosing relays and the analysis confirms there is not a reliability need to include these relays.

At the second generating station, one of the lines exiting the station is approximately two miles in length. The generating units were unstable for faults anywhere on this line. Proposed Reliability Standard PRC-005-3 would be applicable to reclosing relays at the remote bus because it is less than 10 miles from the generating station. In this case the generating units remain stable for close-in faults on each of the lines terminating at the remote bus, confirming that the criterion is conservative.

3. Changes to Requirements in Reliability Standard PRC-005-2

The proposed Reliability Standard consists of five Requirements. The Requirements and the associated Measures have been modified, as necessary, to add in the coverage of Automatic Reclosing to the Requirement language.

Requirement R1 now requires that Transmission Owners, Generator Owners, and Distribution Providers establish a Protection System Maintenance Program both for Protection Systems and for Automatic Reclosing relays as defined in the proposed Reliability Standard, and, as in Reliability Standard PRC-005-2, includes guidelines for the development of such a program.

Requirement R3 now requires Transmission Owners, Generator Owners, and Distribution Providers that utilize time-based maintenance programs to maintain Protection Systems and certain automatic reclosing relays as defined within the proposed Reliability Standard.

Requirement R4 now requires Transmission Owners, Generator Owners, and Distribution Providers that utilize performance-based maintenance programs to implement and follow a PSMP for Protection Systems and for Automatic Reclosing relays as defined within the proposed Reliability Standard.

Revisions to Requirements R2 and R5 were not necessary as each will apply in the same fashion in proposed Reliability Standard PRC-005-3 as approved by the Commission in Reliability Standard PRC-005-2.

D. Implementation Plan

The Implementation Plan for proposed Reliability Standard PRC-005-3 addresses both Protection Systems and Automatic Reclosing. PRC-005-2 has recently been approved by the Commission and has a twelve-year phased-in implementation period. The compliance dates for the various Requirements with respect to maintenance of Protection System Components in PRC-005-2 key off of the date of approval by the applicable regulatory authority. To account for this timing, and in order not to lose time on maintenance activities completed prior to the approval of PRC-005-3, the Standard Drafting Team has carried forward the language in the

implementation plan for PRC-005-2 and modified it to add compliance dates for the Requirements with respect to Automatic Reclosing Components. The Standard Drafting Team also modified the language for the compliance dates for Requirements with respect to Protection System Components to explicitly reference that the compliance timing for these Components counts forward from the applicable regulatory authority approval date for PRC-005-2. As a result, the Implementation Plan for PRC-005-3 captures the necessary implementation information for PRC-005-2. Under the Implementation Plan for PRC-005-3, entities will now, as an initial matter, indicate whether their Component is being maintained under one of the legacy Reliability Standards (PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0) or whether the Component is being maintained pursuant to PRC-005-3. Because PRC-005-3 has carried the Requirements from PRC-005-2 forward, including language regarding implementation timing, there is no need for an entity to cite to the version 2 Reliability Standard during the phased-in implementation period once the proposed Reliability Standard is approved.⁴⁴ Additional aspects of the Implementation Plan are addressed below.

1. Retirement of Legacy Reliability Standards

The Implementation Plan continues to reflect that the retirement of the legacy Reliability Standards will continue to key off of the applicable regulatory approval date of PRC-005-2. Because Automatic Reclosing is a new Component covered by the PRC-005 Reliability Standard, the retirement of the legacy Reliability Standards does not need to correspond with the enforcement date of proposed PRC-005-3. Proposed PRC-005-3 will retire Reliability Standard PRC-005-2 in the United States “at midnight of the day immediately prior to the first day of the

⁴⁴ The same approach will be used with respect to the addition of sudden pressure relays. This will allow for the full retirement of PRC-005-3 and its implementation plan leaving only one version of a new PRC-005 standard as the enforceable Reliability Standard rather than needing to reference versions 2 through 4 for the next twelve years.

first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3.”

2. Compliance Timeframes for Each Requirement

The Implementation Plan includes identical timeframes for entities to become compliant with the Requirements in PRC-005-3 as exist in the implementation plan for PRC-005-2. The only difference is the date from which entities will count forward to determine the date the entity must be compliant for a particular Component Type. Entities will continue to calculate compliance dates for Requirements in connection with any Protection System Components by counting forward from the applicable regulatory approval date of PRC-005-2. Entities will continue to calculate compliance dates for Requirements in connection with any Automatic Reclosing Components by counting forward from the applicable regulatory approval date of PRC-005-3.

3. Newly Identified Automatic Reclosing Components

The Implementation Plan also includes implementation timeframes for newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area. Additional applicable Automatic Reclosing Components may be identified because of the addition or retirement of generating units; or increases of gross generation capacity of individual generating units or plants within the Balancing Authority Area. The Implementation Plan provides that “ [i]n such cases, the responsible entities must complete the maintenance activities, described in Table 4, for the newly identified Automatic Reclosing Components prior to the end of the third calendar year following the identification of those Components unless documented prior maintenance fulfilling the requirements of Table 4 is available.”

E. Evidence Retention Periods

In order to establish effective maintenance procedures to ensure Reliable Operation of the Bulk-Power System, the Standard Drafting Team established certain evidence retention periods, which were approved by the Commission with Reliability Standard PRC-005-2. Those same evidence retention periods are maintained in proposed Reliability Standard PRC-005-3. These periods will now apply to evidence retained for compliance with the Requirements in connection with Automatic Reclosing. Proposed PRC-005-3 continues to require entities to maintain documentation for the longer of: (1) the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component; (2) all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date. The Standard Drafting Team explains that this requirement assures that documentation is available to show that the time between maintenance cycles correctly meets the maintenance interval limits.⁴⁵ Maintaining elements according to these intervals is a critical aspect of properly maintaining a covered Component. Because some maintenance intervals in proposed PRC-005-3 (and the predecessor Reliability Standard PRC-005-2) are up to twelve years, it is possible that an entity may need to retain records for up to twenty-four years.

The evidence retention periods in proposed Reliability Standard PRC-005-3⁴⁶ continue to be reasonable for this type of activity. The type of evidence entities will retain to demonstrate that maintenance was last completed within a given interval are the usual and customary documents maintained by these entities today to document maintenance internally of various

⁴⁵ See *Supplementary and FAQ*, Ex. E at 39.

⁴⁶ The evidence retention periods are outlined in the Compliance section of proposed Reliability Standard PRC-005-3, attached hereto as **Exhibit A**. The written description of the evidence retention periods corresponds to the Maintenance Interval and Maintenance Activities section of Table 1, also found in **Exhibit A**.

components. While the time intervals may seem longer than an entity may reasonably retain such records, the lengthy periods are necessary to establish maintenance has occurred according to the mandated intervals. Retaining records for the two most recent performances of each distinct maintenance activity, where the interval is twelve years, is how the twenty-four year retention period arises. Shortening the time period for retention would require that the maintenance intervals be reduced as well, which would significantly increase capital maintenance costs since entities would need to maintain Components under tighter time constraints.

The Measures in the proposed Reliability Standard provide examples of acceptable types of evidence for each Requirement, but the Measures do not mandate specific records be kept. Therefore, entities will have the flexibility to determine the level of documentation needed to verify this limited element of the proposed Reliability Standard. Generally, entities will likely only maintain summaries of their maintenance activities pertaining to the prior period in order to establish that the proper intervals were met. Therefore, the burden will be minimal compared to the increased capital costs that would result from shortening the intervals to create a shorter maximum retention time.

Recognizing that the period is long, NERC has requested that the Standard Drafting Team consider possible alternatives or refinements to the evidence retention periods in the PRC-005 Reliability Standard for all covered Component Types as part of NERC Project 2007-17.3 – Protection System Maintenance and Testing (Sudden Pressure Relays).

F. Enforceability of proposed Reliability Standard PRC-005-3

The proposed Reliability Standard includes Violation Risk Factors (“VRFs”) and Violation Severity Levels (“VSLs”). The VRFs and VSLs for the proposed Reliability Standard

comport with NERC and Commission guidelines related to their assignment. For a detailed review of the VRFs, the VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines, please see **Exhibit G**.

Because the Requirements contained in proposed Reliability Standard PRC-005-3 track with those contained in the already approved Reliability Standard PRC-005-2, the Standard Drafting Team determined that no revisions were necessary to the VRFs for the proposed Reliability Standard. NERC, therefore, requests that the Commission approve the VRFs as applied to the Automatic Reclosing Components now included in the proposed Reliability Standard.

The VSLs in PRC-005-2 have been revised accordingly to add the additional Component into the levels of severity. The changes are consistent with the approach taken for the VSLs in Reliability Standard PRC-005-2. The VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standard for each of the Component Types.

The proposed Reliability Standard also include Measures that support each Requirement to help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

V. CONCLUSION

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

- approve the proposed Reliability Standard and other associated elements included in **Exhibit A**;
- the new and revised definitions, as noted herein;
- the VRFs and VSLs (as explained in **Exhibit E**);
- approve the Implementation Plan included in **Exhibit B**; and
- approve the retirement of Reliability Standard PRC-005-2, as proposed in the Implementation Plan.

Respectfully submitted,

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Date: February 14, 2014

Exhibit A

Proposed Reliability Standard

A. Introduction

- 1. Title:** **Protection System and Automatic Reclosing Maintenance**
- 2. Number:** PRC-005-3
- 3. Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
- 4. Applicability:**
 - 4.1. Functional Entities:**
 - 4.1.1** Transmission Owner
 - 4.1.2** Generator Owner
 - 4.1.3** Distribution Provider
 - 4.2. Facilities:**
 - 4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4** Protection Systems installed as a Special Protection System (SPS) for BES reliability.
 - 4.2.5** Protection Systems for 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 for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
 - 4.2.6** Automatic Reclosing¹, including:
 - 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

¹ Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

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

5. Effective Date: See Implementation Plan

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

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

B. Requirements

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

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

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

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate

monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.3. Evidence Retention

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

Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

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

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

1.4. Additional Compliance Information

None.

Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 3) Maintained a Segment with

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				less than 60 Components OR 4) Failed to: <ul style="list-style-type: none"> • Annually update the list of Components, <li style="text-align: center;">OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, <li style="text-align: center;">OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance

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

E. Regional Variances

None

F. Supplemental Reference Document

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

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 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

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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 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing	
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval²	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

² For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). 	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

<p align="center">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)</p> <p align="center">Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

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<p align="center">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)</p> <p align="center">Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

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

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

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Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3)		
Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

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

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	<p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate. <p>For microprocessor relays:</p> <ul style="list-style-type: none"> • 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.
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> • 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. <p>Alarming for power supply failure (See Table 2).</p>	12 Calendar Years	<p>Verify:</p> <ul style="list-style-type: none"> • 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
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • 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). <p>Alarming for change of settings (See Table 2).</p>	12 Calendar Years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

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Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). 	12 Calendar Years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an SPS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

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

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

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

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

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

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

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

A. Introduction

1. **Title:** Protection System and Automatic Reclosing Maintenance
2. **Number:** PRC-005-~~23~~
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that ~~these Protection Systemsthey~~ are kept in working order.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Transmission Owner
 - 4.1.2 Generator Owner
 - 4.1.3 Distribution Provider
 - 4.2. **Facilities:**
 - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4 Protection Systems installed as a Special Protection System (SPS) for BES reliability.
 - 4.2.5 Protection Systems for 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 for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
 - 4.2.6 Automatic Reclosing¹, including:
 - 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

¹ Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

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

5. Effective Date: See Implementation Plan

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

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

B. Requirements

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

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

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 34-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

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

- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 34-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*]
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

~~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.~~

C. Measures

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

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each ~~protection~~Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 34-1 through 4-2. (Part 1.2)

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

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

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

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

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.3. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

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

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p><u>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</u></p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3, <u>and Tables 4-1 through 4-2</u> where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity <u>entity’s</u> PSMP failed to specify whether three <u>four</u> or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p>

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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: <ul style="list-style-type: none"> • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the segmentSegment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3, <u>and Tables 4-1 through 4-2.</u>	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3, <u>and Tables 4-1 through 4-2.</u>	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3, <u>and Tables 4-1 through 4-2.</u>	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3, <u>and Tables 4-1 through 4-2.</u>
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain

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

E. Regional Variances

None

F. Supplemental Reference Document

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

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 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

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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 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	<u>Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0</u>
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section.	
<u>23</u>	December 19 <u>November 7,</u> 2013	FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014. Adopted by the <u>NERC Board of Trustees</u>	<u>Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.</u>

Table 1-1
 Component Type - Protective Relay
 Excluding distributed UFLS and distributed UVLS (see Table 3)

Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • 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). 	<p>12 calendar years <u>Calendar</u> <u>Years</u></p>	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

Table 1-2
Component Type - Communications Systems
Excluding distributed UFLS and distributed UVLS (see Table 3)

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
<p>Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.</p>	<p>4 calendar months</p>	<p>Verify that the communications system is functional.</p>
	<p>6 calendar years</p>	<p>Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).</p> <p>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.</p>
<p>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).</p>	<p>12 calendar years</p>	<p>Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).</p> <p>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.</p>
<p>Any communications system with all of the following:</p> <ul style="list-style-type: none"> • 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). 	<p>12 calendar years</p>	<p>Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System</p>

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
<u>Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.</u>	<u>4 Calendar Months</u>	<u>Verify that the communications system is functional.</u>
	<u>6 Calendar Years</u>	<u>Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).</u> <u>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.</u>
<u>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).</u>	<u>12 Calendar Years</u>	<u>Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).</u> <u>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.</u>

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<p>Any voltage and current sensing devices not having<u>communications system with all of the following:</u></p> <ul style="list-style-type: none"> Continuous monitoring attributes of the category below 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). 	<p>12 calendar years<u>Calendar Years</u></p>	<p>Verify <u>only the unmonitored communications system inputs and outputs that current and voltage signal values are provided essential to the protective relays.</u> proper functioning of the Protection System</p>
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<p align="center"><u>Table 1-3</u> <u>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays</u> <u>Excluding distributed UFLS and distributed UVLS (see Table 3)</u></p>		
<p align="center"><u>Component Attributes</u></p>	<p align="center"><u>Maximum Maintenance Interval</u></p>	<p align="center"><u>Maintenance Activities</u></p>
<p><u>Any voltage and current sensing devices not having monitoring attributes of the category below.</u></p>	<p><u>12 Calendar Years</u></p>	<p><u>Verify that current and voltage signal values are provided to the protective relays.</u></p>
<p>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).</p>	<p>No periodic maintenance specified</p>	<p>None.</p>

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	-Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

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

Table 1-4(f)		
Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 calendar years <u>Calendar Years</u>	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 <u>Calendar Years</u>	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS. <u>(See Table 4-2(b) for SPS which include Automatic Reclosing.)</u>	12 calendar years <u>Calendar Years</u>	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 calendar years <u>Calendar Years</u>	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 SPSSPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

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

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years Calendar Years	Verify that settings are as specified. For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate. For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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 Calendar Years	Verify: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 calendar years 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 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 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 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		
<u>Component Attributes</u>	<u>Maximum Maintenance Interval</u>	<u>Maintenance Activities</u>
<p><u>Any unmonitored reclosing relay not having all the monitoring attributes of a category below.</u></p>	<p><u>6 Calendar Years</u></p>	<p><u>Verify that settings are as specified.</u></p> <p><u>For non-microprocessor relays:</u></p> <ul style="list-style-type: none"> • <u>Test and, if necessary calibrate</u> <p><u>For microprocessor relays:</u></p> <ul style="list-style-type: none"> • <u>Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</u>
<p><u>Monitored microprocessor reclosing relay with the following:</u></p> <ul style="list-style-type: none"> • <u>Internal self diagnosis and alarming (See Table 2).</u> • <u>Alarming for power supply failure (See Table 2).</u> 	<p><u>12 Calendar Years</u></p>	<p><u>Verify:</u></p> <ul style="list-style-type: none"> • <u>Settings are as specified.</u> • <u>Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</u>

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
<u>Component Attributes</u>	<u>Maximum Maintenance Interval</u>	<u>Maintenance Activities</u>
<u>Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.</u>	<u>12 Calendar Years</u>	<u>Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.</u>
<u>Control circuitry associated with Automatic Reclosing that is not part of an SPS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)</u>	<u>No periodic maintenance specified</u>	<u>None.</u>

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

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

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

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

1. Develop a list with a description of Components included in each designated Segment ~~of the Protection System Component population~~, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 ~~and~~, Table 3, ~~and Tables 4-1 through 4-2~~ until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

~~**Segment**—Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.~~

~~**Countable Event**—A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.~~

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

1. At least annually, update the list of ~~Protection System~~ Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.

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3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a ~~Protection System~~ Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Exhibit B
Implementation Plan

Implementation Plan Protection System and Automatic Reclosing Maintenance PRC-005-3

Standards Involved

Approval:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Retirements:

- PRC-005-2 – Protection System Maintenance
- PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 – Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program
- PRC-011-0 – Undervoltage Load Shedding System Maintenance and Testing
- PRC-017-0 – Special Protection System Maintenance and Testing

Prerequisite Approvals:

N/A

Background:

Reliability Standard PRC-005-2 with its associated Implementation Plan was approved by the NERC Board of Trustees in November 2012 and has been filed with the applicable regulatory authorities for approval. The Implementation Plan for PRC-005-3 addresses both Protection Systems as outlined in PRC-005-2 and Automatic Reclosing components. PRC-005-3 establishes minimum maintenance activities for Automatic Reclosing Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-3 requires entities to revise the Protection System Maintenance Program by now including Automatic Reclosing Components. The implementation plan established under PRC-005-2 remains unchanged except for the addition of Automatic Reclosing Components required under PRC-005-3.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry-forward requirements from PRC-005-2, establish minimum maintenance activities for Protection System and Automatic Reclosing Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.

2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.
3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth below in this document carries forward the implementation schedules contained in PRC-005-2 and includes changes needed to address the addition of Automatic Reclosing Components in PRC-005-3.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standard PRC-005-3, in accordance with this implementation plan.

While entities are transitioning to the requirements of PRC-005-2, or the combined successor standard PRC-005-3, each entity must be prepared to identify:

- All of its applicable Protection System and Automatic Reclosing Components.
- Whether each component has last been maintained according to PRC-005-2 (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof.

For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active throughout the phased implementation period of PRC-005-3 and shall be applicable to an entity's Protection System Component maintenance activities not yet transitioned to PRC-005-3. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2.

The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees' adoption.

Implementation Plan for Definition:

Protection System Maintenance Program – Entities shall use this definition when implementing any portions of R1, R2 R3, R4 and R5 which use this defined term.

Implementation Plan for Requirements R1, R2 and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
6. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or

as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
7. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area:

This applies to PRC-005-3 and successor standards.

Additional applicable Automatic Reclosing Components may be identified because of the addition or retirement of generating units; or increases of gross generation capacity of individual generating units or plants within the Balancing Authority Area.

In such cases, the responsible entities must complete the maintenance activities, described in Table 4, for the newly identified Automatic Reclosing Components prior to the end of the third calendar year following the identification of those Components unless documented prior maintenance fulfilling the requirements of Table 4 is available.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Implementation Plan

~~Project 2007-17 Protection Systems~~ System and Automatic ~~Reclosing Maintenance and Testing~~ PRC-005-~~023~~

Standards Involved

Approval:

- ~~PRC-005-23~~ – Protection System ~~and Automatic Reclosing~~ Maintenance

Retirements:

- ~~PRC-005-2~~ – Protection System Maintenance
- PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 – Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program
- PRC-011-0 – Undervoltage Load Shedding System Maintenance and Testing
- PRC-017-0 – Special Protection System Maintenance and Testing

Prerequisite Approvals:

~~Revised definition of “Protection System”~~

N/A

Background:

Reliability Standard PRC-005-2 with its associated Implementation Plan was approved by the NERC Board of Trustees in November 2012 and has been filed with the applicable regulatory authorities for approval. The Implementation Plan for PRC-005-3 addresses both Protection Systems as outlined in PRC-005-2 and Automatic Reclosing components. PRC-005-3 establishes minimum maintenance activities for Automatic Reclosing Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-3 requires entities to revise the Protection System Maintenance Program by now including Automatic Reclosing Components. The implementation plan established under PRC-005-2 remains unchanged except for the addition of Automatic Reclosing Components required under PRC-005-3.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry-forward requirements from PRC-005-2, establish minimum maintenance activities for Protection System ~~component types and~~

On October 17, 2013, the Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section.

- Automatic Reclosing Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.
2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.
 3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.

- ~~4. The Implementation Schedule set forth in this document requires that entities develop their revised Protection System Maintenance Program within twelve (12) months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty four (24) months following NERC Board of Trustees' adoption. This anticipates that it will take approximately twelve (12) months to achieve regulatory approvals following adoption by the NERC Board of Trustees.~~
4. The Implementation Schedule set forth below in this document carries forward the implementation schedules contained in PRC-005-2 and includes changes needed to address the addition of Automatic Reclosing Components in PRC-005-3.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2 ~~in accordance with this implementation plan. Each entity shall be responsible for maintaining each of their Protection System components according to their maintenance program already in place for the legacy standards (PRC 005 1b, PRC 008 0, PRC 011 0, and PRC 017 0) or according to their maintenance program for PRC 005 2, but not both. Once an entity has designated PRC 005 2 as its maintenance program for specific Protection System components, they cannot revert to the original program for those components., or the combined successor standard PRC-005-3, in accordance with this implementation plan.~~

While entities are transitioning to the requirements of PRC-005-2, or the combined successor standard PRC-005-3, each entity must be prepared to identify:

- All of its applicable Protection System ~~components~~ and Automatic Reclosing Components.
- Whether each component has last been maintained according to PRC-005-2 ~~or under~~ (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, ~~or~~ PRC-017-0, or a combination thereof.

For activities being added to an entity's program as part of PRC-005-~~23~~ implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-~~23~~.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0, ~~which are being replaced by PRC-005-2,~~ shall remain active throughout the phased implementation period of PRC-005-~~23~~ and shall be applicable to an entity's Protection System ~~component~~**Component** maintenance activities not yet transitioned to PRC-005-~~2-3~~. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2.

The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees' adoption.

Implementation Plan for Definition:

Protection System Maintenance Program – Entities shall use this definition when implementing any portions of R1, R2 R3, R4 and R5 which use this defined term.

Implementation Plan for Requirements R1, R2 and R5:

Entities For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System ~~component~~Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
2. For Protection System ~~component~~Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
3. For Protection System ~~component~~Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:
 - The entity shall be at least 30% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the

- November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
4. For Protection System ~~component~~Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:
- The entity shall be at least 30% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
5. For ~~Protection System component~~Automatic Reclosing Component maintenance activities with maximum allowable intervals of ~~twelve (12)~~six (6) calendar years, as established in ~~Tables 1-1 through 1-5, Table 2, and Table 3-4~~:

- ~~The entity shall be at least 30% compliant with PRC-005-2~~ The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- ~~The entity shall be at least 60% compliant with PRC-005-2~~ The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval, of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval, of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC

Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

7. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area:

This applies to PRC-005-3 and successor standards.

Additional applicable Automatic Reclosing Components may be identified because of the addition or retirement of generating units; or increases of gross generation capacity of individual generating units or plants within the Balancing Authority Area.

In such cases, the responsible entities must complete the maintenance activities, described in Table 4, for the newly identified Automatic Reclosing Components prior to the end of the third calendar year following the identification of those Components unless documented prior maintenance fulfilling the requirements of Table 4 is available.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- ~~Distribution Provider~~

-

Exhibit C
Order No. 672 Criteria

Order No. 672 Criteria

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

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

The purpose of proposed Reliability Standard PRC-005-3 is to document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System so that they are kept in working order. The revised Reliability Standard requires that entities develop an appropriate Protection System Maintenance Program, that they implement their program, and that, in the event they are unable to restore Automatic Reclosing Components to proper working order while performing maintenance, they initiate the follow-up activities necessary to resolve those maintenance issues. Proposed PRC-

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

² Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

005-3 adds detailed tables of minimum maintenance activities and maximum maintenance intervals for Automatic Reclosing to the existing PRC-005-2 Reliability Standard, extending the benefits of a strong maintenance program to these Components. The subset of Automatic Reclosing applications included in proposed PRC-005-3 is based on the findings of the SAMS/SPCS Report included as **Exhibit D**. The proposed Reliability Standard is also designed to fulfill the Commission's directive in Order No. 758 regarding the addition of certain reclosing relays to the PRC-005 Reliability Standard.

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

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Aside from minor modifications to facilitate coverage of Automatic Reclosing in the Reliability Standard, the Requirements previously-approved by the Commission in PRC-005-2 are unchanged. The proposed Reliability Standard applies to Generator Owners, Transmission Owners, and Distribution Providers and clearly articulates the actions that each entity must take to comply with the proposed Reliability Standard.

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

³ Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

⁴ Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

Because the Requirements contained in proposed Reliability Standard PRC-005-3 have not changed compared to those contained in the Commission-approved Reliability Standard PRC-005-2, the Standard Drafting Team determined that no revisions were necessary to the VRFs for the proposed Reliability Standard. NERC, therefore, requests that the Commission approve the VRFs as applied to the additional Automatic Reclosing Components now included in the proposed Reliability Standard.

The VSLs in PRC-005-2 have been revised accordingly to add the additional Component into the levels of severity. The changes are consistent with the approach taken for the VSLs in Reliability Standard PRC-005-2.

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

The proposed Reliability Standard continues to include Measures that support the Requirements by clearly identifying what is required and how the Requirement will be enforced. The Measures have been slightly modified to include Automatic Reclosing references where necessary. The proposed Measures are as follows:

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1. For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer's specifications or engineering drawings) of the

⁵ Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

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

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

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

These Measures help provide clarity regarding how the Requirements will be enforced, and help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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

The proposed Reliability Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard includes certain applications of Automatic Reclosing as explained in the Petition and reflected in the Applicability section of the proposed Reliability Standard. NERC engaged the NERC System Analysis and Modeling Subcommittee (“SAMS”) and the System Protection and Control Subcommittee (“SPCS”), both subcommittees of the NERC Planning Committee, to support the Project 2007-17 Standard Drafting Team assigned to modify PRC-005. The SAMS/SPCS Report (**Exhibit D**) recommends technical bases to identify those reclosing applications that may affect the Reliable Operation of the Bulk-Power System. These applications have been included in the Applicability section of PRC-005 to address the directives in Order No. 758. By engaging the NERC technical subcommittees of the Planning Committee in the analysis to determine what applications of reclosing should be included, the proposed Reliability Standard does not over-include applications that do not affect reliability. Engaging the technical committees in this analysis assisted the Standard Drafting Team in reaching the most efficient and effective determination regarding the Applicability changes in the proposed Reliability Standard.

6. Proposed Reliability Standards cannot be “lowest common denominator,” *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.⁷

⁶ Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or “best practice,” for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

⁷ Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO’s Reliability Standard development process based on the least effective North American practice — the so-called “lowest common denominator” — if such practice does not adequately protect Bulk-Power System reliability.

The proposed Reliability Standard does not reflect a “lowest common denominator” approach. In addition to satisfying a Commission directive, the revisions contained in the proposed Reliability Standard require expanded application of maintenance plans and processes, helping to preserve reliability by addressing potential issues before they impact reliability. The Automatic Reclosing applications included in the proposed Reliability Standard also reflect detailed study by two of NERC’s technical subcommittees, as noted above and in the Petition. Lastly, NERC staff conducted additional technical analysis to confirm the effectiveness of certain aspects of the proposed Reliability Standard such as the 10-mile threshold included in the Applicability section.

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

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model.

Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a “lowest common denominator” Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

⁸ Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

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

Proposed Reliability Standard PRC-005-3 has no undue negative effect on competition.

The proposed Reliability Standard requires the same performance by each of the applicable Functional Entities—Generator Owners, Transmission Owners, and Distribution Providers—in requiring the development of maintenance plans for Automatic Reclosing.

The proposed Reliability Standard does not unreasonably restrict the available generation or transmission capability or limit use of the Bulk-Power System in a preferential manner.

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

The proposed effective dates for the proposed Reliability Standard are just and reasonable and appropriately balance the urgency in the need to implement the proposed Reliability Standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. This will allow applicable entities adequate time to ensure compliance with the Requirements. The proposed effective dates are explained in the proposed Implementation Plan, attached as **Exhibit B**. Except for the addition of certain applications of Automatic Reclosing, the Implementation Plan remains unchanged from the Commission-approved version attached to Reliability Standard

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

¹⁰ Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

PRC-005-2. The same timeframes for compliance with the Requirements will apply counting forward from the effective date of an order approving proposed PRC-005-3.

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

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

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the Standard Drafting Team were properly noticed and open to the public. The initial and recirculation ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.¹²

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standard. No comments were received indicating the proposed Reliability Standard is in conflict with other vital public interests.

¹¹ Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

¹² Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

12. Proposed Reliability Standards must consider any other appropriate factors.¹³

No other factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

¹³ Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

NERC SAMS-SPCS Joint Autoreclosing Report

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Considerations for Maintenance and Testing of Autoreclosing Schemes

System Analysis and Modeling Subcommittee
System Protection and Control Subcommittee

November 2012

RELIABILITY | ACCOUNTABILITY



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NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to enhance the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.¹

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

NERC Regional Entities	
FRCC Florida Reliability Coordinating Council	SERC SERC Reliability Corporation
MRO Midwest Reliability Organization	SPP RE Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	TRE Texas Reliability Entity
RF ReliabilityFirst Corporation	WECC Western Electricity Coordinating Council

¹ As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the “electric reliability organization” under Alberta’s Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l’énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC’s reliability standards are also mandatory in Nova Scotia and British Columbia. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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This technical document was approved by the NERC Planning Committee on November 14, 2012.

Introduction

On February 3, 2012, the Federal Energy Regulatory Commission (FERC) issued Order No. 758² approving an interpretation of NERC Reliability Standard PRC-005-1, Transmission and Generation Protection System Maintenance and Testing. In addition to approving the interpretation, the Commission directed that concerns identified in the preceding Notice of Proposed Rulemaking (NOPR) be addressed within the reinitiated PRC-005 revisions.

The concerns raised in the NOPR pertain to automatic reclosing (autoreclosing) relays that are either “used in coordination with a Protection System to achieve or meet system performance requirements established in other Commission-approved Reliability Standards, or can exacerbate fault conditions when not properly maintained and coordinated,” in which case “excluding the maintenance and testing of these reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the Bulk-Power System.”³ To address these concerns, the Commission concludes that “specific requirements or selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System.”⁴

This report provides technical input from the NERC System Analysis and Modeling Subcommittee (SAMS) and the System Protection and Control Subcommittee (SPCS), both subcommittees of the NERC Planning Committee, to support the Project 2007-17 standard drafting team assigned to modify PRC-005. This report recommends technical bases to identify those autoreclosing applications that may affect reliability of the bulk power system. Such applications should be included in the Applicability section of PRC-005 to address the directives in Order No. 758.

² See FERC Order No. 758, [Interpretation of Protection System Reliability Standard](#), 138 FERC ¶ 61,094.

³ *Id.* at P. 16.

⁴ *Id.* at P. 26.

Considerations for Applicability of PRC-005

Autoreclosing is utilized on transmission systems to restore transmission elements to service following automatic circuit breaker tripping. When an autoreclosing application may affect reliability of the bulk power system, the autoreclosing relay⁵ should be included in the applicability of PRC-005.

The concerns identified by the Commission in Order No. 758 can be grouped into two categories:

- situations in which autoreclosing fails to operate when required to maintain bulk power system reliability; and
- situations in which autoreclosing operates in manner that is not consistent with its design, adversely affecting reliability of the bulk power system.

The following sections address these two categories of concern.

Applications to Improve Bulk Power System Performance

Consideration of Autoreclosing to Increase Operating Limits

Planning and operation of the bulk power system must consider autoreclosing applications.⁶ Autoreclosing following automatic circuit breaker tripping may be successful if the condition that initiated the tripping (e.g., a fault) is no longer present, or it may be unsuccessful if the condition is still present in which case the circuit breaker will trip again. While successful autoreclosing enhances reliability of the bulk power system, autoreclosing into a permanent fault may adversely affect reliability. Since the potential for autoreclosing into a permanent fault exists for any application, it is not possible to depend on successful autoreclosing as a means to meet the system performance requirements in the NERC Reliability Standards or to increase the transfer limit associated with an Interconnection Reliability Operating Limit⁷ (IROL).

Single-pole tripping and autoreclosing also may be used to minimize the impact to the system for a single-phase fault; however, the same issues exist for single-pole autoreclosing with regard to the potential for an autoreclose into a permanent fault after which all three poles are tripped. In the event an autoreclosing relay fails to initiate reclosing after a single-pole trip, protective functions will detect the condition and trip all three poles after a time delay.

SAMS and SPCS have not identified an application in which autoreclosing is used in coordination with a protection system to meet the system performance requirements in a NERC Reliability

⁵ Autoreclosing relays in this context include dedicated autoreclosing relays and the autoreclosing function in multi-function relays.

⁶ For example, TPL-001-2, adopted by the NERC Board of Trustees on August 4, 2011, requires that analyses include the impact of subsequent successful high-speed autoreclosing and unsuccessful high-speed autoreclosing into a fault where high-speed autoreclosing is utilized.

⁷ Capitalized as referenced in the NERC Glossary of Terms.

Standard or in establishing an IROL. As discussed above, the need to consider autoreclosing into a permanent fault precludes dependency on autoreclosing for this purpose. SAMS and SPCS therefore recommend that no modification is necessary to the applicability of PRC-005 to address autoreclosing applications necessary for bulk power system performance.

Autoreclosing as Part of a Special Protection System

Special Protection Systems⁸ (SPS) may be applied to meet system performance requirements in the NERC Reliability Standards or to increase the transfer limit associated with an IROL. When autoreclosing is included as an integral part of such a SPS, a failure of the reclosing function may adversely impact bulk power system reliability. NERC Reliability Standard PRC-005-2⁹ includes minimum maintenance activities and maximum intervals for SPS. SAMS and SPCS recommend that PRC-005 be modified to explicitly address maintenance and testing of autoreclosing relays applied as an integral part of a SPS.

Applications to Aid Restoration

Autoreclosing typically is installed to alleviate the burden on operators of manually restoring transmission lines. Autoreclosing also provides improved availability of overhead transmission lines. The degree to which availability is improved depends on the nature of the fault (permanent or temporary) and on transmission operator practices for manually restoring lines. While faster restoration of transmission lines following temporary faults does provide an inherent reliability benefit, this section addresses applications that are not necessary to meet system performance requirements in NERC Reliability Standards. In these applications it is possible for undesired operation of the autoreclosing scheme, not consistent with its design, to adversely affect system reliability. The following sections discuss credible failure modes that may lead to undesired operation and the associated potential reliability impacts to the bulk power system, to identify applications that should be included in the Applicability section of PRC-005.

Credible Failure Modes of Autoreclosing Schemes

This section discusses credible failure modes of autoreclosing schemes. These failure modes are assessed in the next section to identify which may impact reliability of the bulk power system. Applications for which one or more of these failure modes could adversely affect reliability will be provided to the Project 2007-17 standard drafting team to support development of revisions to PRC-005 directed in Order No. 758.

There are many different types of autoreclosing relays. Autoreclosing relays may be electromechanical (and comprised of discrete components), solid state, or microprocessor-based and may be applied in a variety of autoreclosing schemes. Regardless of the type of autoreclosing scheme or vintage of design of the autoreclosing relay, there are a few main characteristics shared by most autoreclosing relays. These include:

⁸ Capitalized as referenced in the NERC Glossary of Terms.

⁹ PRC-005-2 achieved 81.08 percent quorum and 80.51 percent approval in a recirculation ballot that ended October 24, 2012.

- **Supervision Functions:** Supervising elements typically monitor one or more voltage phases to determine if a circuit is energized (live), de-energized (dead), or in synchronism with another circuit, etc. Other types of supervision may be used to perform selective autoreclosing; e.g., autoreclosing is blocked for the detection of a three-phase fault, or for the loss of a communication channel. In some applications, autoreclosing is unsupervised.
- **Timing Functions:** Timing elements perform various timing duties with the most important being the desired time delay to issue a circuit breaker close; the minimum time delay being dictated by de-ionization time. In some applications, autoreclosing is initiated by protective relaying and issues a close signal with little or no intentional time delay.
- **Output Function:** The output function is typically some type of relay with contacts that close and apply DC voltage to the close circuit to effect a circuit breaker close.

When analyzing autoreclosing relay failure modes, the functions described above are the ones most likely to lead to a failure. The failures can be analyzed without a detailed discussion of the many variations of autoreclosing logic that may be implemented throughout North America. The main failure modes of autoreclosing relays are:

- **Supervision Function Failures:** A failed voltage supervision function that requires a dead line to reclose may incorrectly interpret that the monitored circuit is live and consequently not issue a close signal to a circuit breaker as designed. Conversely, a failed voltage supervision function that requires a live line to reclose may incorrectly interpret that a dead circuit is live and, therefore, incorrectly issue a close signal to a circuit breaker. Further, failure of a synchronism check function may allow a close when static system angles are greater than designed, or inhibit a close when static system angles are less than designed.
- **Timing Function Failures:** Where intentional time delays are used, the time delay circuits may fail and issue a close with no time delay. Failure of the time delay circuits may also inhibit the autoreclosing relay from issuing a close signal.
- **Output Function Failures:** The output relay contacts may fail to close and thus no close signal will be issued to a circuit breaker. The output relay contacts may also fail in the closed position (“weld shut”) and send a constant close signal to a circuit breaker. Solid state outputs can exhibit both of these failure modes. This failure mode can result in one of two possible scenarios depending on the circuit breaker closing circuit design and whether the constant close signal occurs prior to tripping or during the act of reclosing the circuit breaker. One scenario is that no reclose will occur. The second scenario will result in only one reclose being attempted.

Thus, to assess the potential impact of an autoreclosing relay failure on the power system, the following types of failures should be considered:

- No close signal is issued under conditions that meet the intended design conditions. This is the most common failure mode and includes the vast majority of autoreclosing failures.
- A close signal is issued with no time delay or with less time delay than is intended.
- A constant or sustained close signal is issued. In this case, a multi-shot reclose scheme may attempt to reclose only once.
- A close signal is issued for conditions other than the intended supervisory conditions.

Potential Reliability Impacts

In this section each of the identified autoreclosing failure modes is analyzed to assess the potential for adverse impact to bulk power system reliability and the circumstances under which impacts may occur.

1. No close signal is issued under conditions that meet the intended design conditions: A failure to autoreclose would result in a failure to restore a single power system element. The system already must be planned and operated considering that autoreclosing will be unsuccessful. Thus, the impact to power system reliability for this failure mode results in a condition the system is designed to withstand, and therefore this failure mode does not create any additional considerations for inclusion of autoreclosing relays in PRC-005 beyond those related to SPS as discussed in the previous section.
2. A close signal is issued with no time delay or with less time delay than is intended: This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic.

The potential reliability impacts of this failure mode are damage to generators and generator instability. Autoreclosing logic typically is selected to reenergize a dead circuit remote from generating units or strong sources to avoid adverse impacts associated with autoreclosing into a permanent fault. Typically when autoreclosing is applied at a generating station it is only for live-line conditions with synchronism check; however, applications do exist where autoreclosing from a generating station is used such as transmission lines between two generating plants, or radial lines that cannot be energized from another source. Where autoreclosing is applied at or in proximity to a generating station the potential for this failure mode exists.

Premature autoreclosing has the potential to cause generating unit loss of life due to shaft fatigue. Accepted industry guidance is that planned switching operations, such as simple line restoration, should be conducted in a way that avoids significant contribution to cumulative shaft fatigue. Entities typically implement this guidance at generating stations by using time delayed autoreclosing to allow shaft oscillations to dampen, and/or live line autoreclosing or live bus-live line autoreclosing with synchronism check supervision to

minimize shaft torque. By conducting planned switching in this manner, nearly all of the fatigue capability of the shaft is preserved to withstand the impact of unplanned and unavoidable disturbances such as faults, fault clearing, reclosing into system faults, and emergency line switching. Premature autoreclosing due to a supervision failure is a small subset of autoreclosing failures (the overwhelming majority of autoreclosing failures are failure to close) and is an infrequent unplanned disturbance. As a result, it is not necessary to consider the incremental loss of life that may occur for this infrequent event as the basis for whether to include maintenance and testing of autoreclosing relays in PRC-005.

Premature autoreclosing also has the potential to cause generating unit or plant instability. NERC Reliability Standards require consideration of loss of the largest generating unit within a Balancing Authority Area¹⁰; therefore, generation loss would not impact reliability of the bulk power system unless the combined capacity loss exceeds the largest unit within the Balancing Authority Area. Including maintenance and testing of autoreclosing relays in PRC-005 would therefore be appropriate for applications at or in proximity to generating plants with capacity exceeding the largest unit within the Balancing Authority Area. In this context proximity is defined as one bus away if the bus is within 10 miles of the generating plant. Transmission line impedance on the order of 1 mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

At these locations, maintenance and testing of autoreclosing relays should be subject to PRC-005, unless the equipment owner can demonstrate to the Transmission Planner that this failure mode would not result in tripping generating units with combined capacity greater than the largest unit within the Balancing Authority Area. This demonstration should be based on simulation of a close-in three-phase fault for twice the normal clearing time (capturing a minimum trip-close-trip time delay).

3. A constant or sustained close signal is issued: This failure mode can result in one of two possible scenarios depending on the circuit breaker closing circuit design and whether the constant close signal occurs prior to tripping or during the act of reclosing the circuit breaker. One scenario is that no reclose will occur. The second scenario will result in only one reclose being attempted. This scenario results in the worse impact; however this results in an outcome similar to failure mode No. 1 – less reclose attempts than planned. Neither of these failure modes creates any additional considerations for inclusion of autoreclosing relays in PRC-005.
4. A close signal is issued for conditions other than the intended supervisory conditions: This failure mode can result in two different scenarios.

The first scenario is autoreclosing into a dead line with a fault when dead-line closing was not intended. Similar to failure mode No. 2 discussed above, the potential reliability

¹⁰ Capitalized as referenced in the NERC Glossary of Terms.

impacts of this failure mode are instability and damage to generating units. The incidence of this failure mode is similar to failure mode No. 2 and therefore concern may be limited to the potential loss of generating units with combined capacity that exceeds the largest unit within the Balancing Authority Area. Including maintenance and testing of autoreclosing relays in PRC-005 would therefore be appropriate for applications at or in proximity to generating units as noted above. The primary difference between this scenario and failure mode No. 2 is this failure mode does not include a timing failure. As such both this scenario and failure mode No. 2 can lead to unintended autoreclosing into fault; however, the timing of the undesired autoreclosure in this scenario will occur after any intentional time delay included in the autoreclosing relay. For this reason a separate test is not necessary to exclude applications from maintenance and testing under PRC-005. Application of the test described for failure mode No. 2 adequately addresses this failure mode.

The second scenario is autoreclosing into a live line with an angle greater than the acceptance angle necessary to prevent potential equipment damage. The potential reliability impact of this failure mode is damage to generating units. As noted in the discussion of failure mode No. 2, accepted industry guidance is that planned switching operations, such as simple line restoration, should be conducted in a way that avoids significant contribution to cumulative shaft fatigue. By conducting planned switching in this manner, nearly all of the fatigue capability of the shaft is preserved to withstand the impact of unplanned and unavoidable disturbances such as faults, fault clearing, reclosing into system faults, and emergency line switching. Undesired autoreclosing at an angle greater than the sync-check acceptance angle due to a supervision failure is a small subset of autoreclosing failures and is an infrequent unplanned disturbance. As a result, it is not necessary to consider the incremental loss of life that may occur for this infrequent event as the basis for whether to include maintenance and testing of autoreclosing relays in PRC-005.

Maintenance Intervals and Activities

The SPCS reviewed the maximum maintenance intervals and minimum maintenance activities proposed in reliability standard PRC-005-2. Specifically, the SPCS reviewed Table 1-1 which is applicable to protective relays and Table 1-5 which is applicable to control circuitry associated with protective functions (excluding distributed UFLS and distributed UVLS). The SPCS review focused on whether any substantive differences exist between protective relays and autoreclosing relays, or between control circuitry associated with protective functions and circuitry associated with autoreclosing schemes, that would warrant different intervals or activities for maintenance of autoreclosing components.

Autoreclosing Relays

The SPCS concluded that electromechanical, solid-state, and microprocessor based autoreclosing relays are substantially the same with respect to design and manufacturing as their protective relay counterparts. As such, the SPCS recommends that the maximum intervals defined in Table 1-1 of PRC-005-2 should also be applicable to autoreclosing relays that may be subject to future versions of the standard.

The SPCS also assessed the maintenance activities included in Table 1-1 of PRC-005-2 and concluded that the activities are analogous to activities performed during maintenance and testing of autoreclosing relays and therefore Table 1-1 should be applied to autoreclosing relays that may be subject to future versions of the standard. For example, the activity to test and, if necessary calibrate, non-microprocessor relays would be applicable to testing and calibration of electromechanical and solid-state autoreclosing relays, and the activity to verify acceptable measurement of power system input values would be applicable to verification of permissive inputs used for voltage supervision and synchronism check.

Autoreclosing Control Circuitry

Similarly, the SPCS assessed the maintenance intervals and activities included in Table 1-5 of PRC-005-2 and concluded that the intervals and activities for maintaining control circuitry for autoreclosing schemes should be similar to those established for maintaining control circuitry associated with protective functions. The SPCS recommends that Table 1-5 should be applicable to control circuitry associated with autoreclosing relays that may be subject to future versions of the standard. The SPCS also recommends that the standard drafting team include minimum maintenance activities and maximum maintenance intervals for autoreclosing control circuitry that parallel the maintenance activities and intervals established for protective function control circuitry. It should be noted that, consistent with control circuitry defined for protective functions, the SPCS does not consider internal breaker control circuitry (e.g., anti-pump and coil interlock circuits) to be associated with autoreclosing component maintenance. Since the failure to close may represent a risk to reliability when breaker closing is integral to operation of an SPS, the closing coil should be considered in PRC-005. For use within a revision to PRC-005, control circuitry of autoreclosing schemes might be defined as:

“Control circuitry associated with autoreclosing schemes including the close coil, but excluding breaker internal controls such as anti-pump and various interlock circuits.”

Recommendations

SAMS and SPCS recommend the following guidance for future development of NERC Reliability Standard PRC-005, *Transmission and Generation Protection System Maintenance and Testing*, to address the concerns stated in FERC Order No. 758.

1. Modify PRC-005 to explicitly address maintenance and testing of autoreclosing relays applied as an integral part of a SPS.
2. Modify PRC-005 to include maintenance and testing of autoreclosing relays at or in proximity to generating plants at which the total installed capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area.
 - In this context, define proximity as substations one bus away if the substation is within 10 miles of the plant.
 - Include a provision to exclude autoreclosing relays if the equipment owner can demonstrate to the Transmission Planner that a close-in three-phase fault for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of generation in the interconnection exceeding the largest unit within the Balancing Authority Area where the autoreclosing is applied.
3. Base minimum maintenance activities and maximum intervals on the activities and intervals in PRC-005-2.
 - Develop minimum maintenance activities and maximum intervals for autoreclosing relays similar to Table 1-1.
 - Develop minimum maintenance activities and maximum intervals for control circuitry of autoreclosing schemes similar to Table 1-5.
 - For the purpose of PRC-005, define control circuitry of autoreclosing schemes as: “Control circuitry associated with autoreclosing schemes including the close coil, but excluding breaker internal controls such as anti-pump and various interlock circuits.”

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Exhibit E

Supplementary Reference and FAQ Document

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Supplementary Reference and FAQ

PRC-005-3 Protection System Maintenance

October 2013

RELIABILITY | ACCOUNTABILITY



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1. Introduction and Summary

Note: This supplementary reference for PRC-005-3 is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive, and, when approved, will supersede PRC-005-2.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-3 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the [NERC Glossary of Terms](#) used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- 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.

2.3 Applicability of New Protection System Maintenance Standards

The BES purpose is to transfer bulk power. The applicability language has been changed from the original PRC-005:

“...affecting the reliability of the Bulk Electric System (BES)...”

To the present language:

“...that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).”

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution

Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

NERC's approved definition of Bulk Electric System is:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.

The BES definition is presently undergoing the process of revision.

Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a [June 14, 2007 Informational Filing](#).

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your “non-BES circuit breaker” has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the “Facilities” section of “Applicability” track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Special Protection Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 94 (tripping or trip-free relay), as these devices are tripping relays that respond to the trip signal of the protective relay that processed the signals from the current and voltage-sensing devices.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.6.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

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.

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 a SPS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that

a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES unit within the Balancing Authority Area where the Automatic Reclosing is applied.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

How do I interpret Applicability Section 4.2.6 to determine applicability in the following examples:

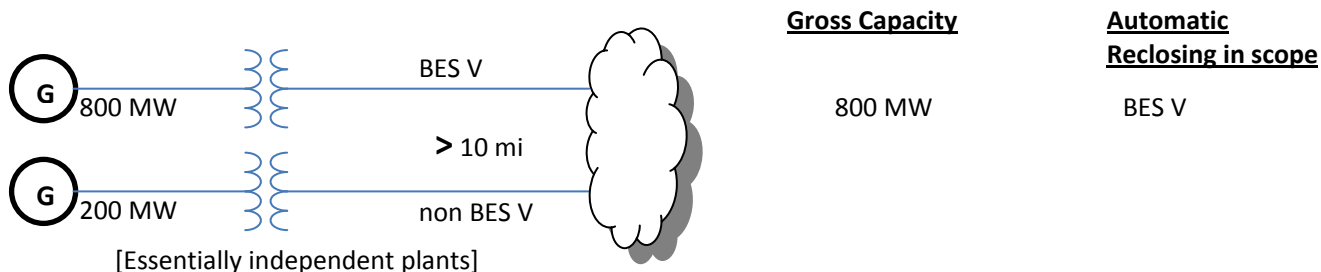
At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.

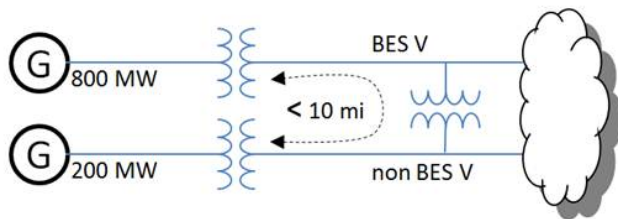


Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



Gross Capacity

1000 MW

Automatic Reclosing in scope

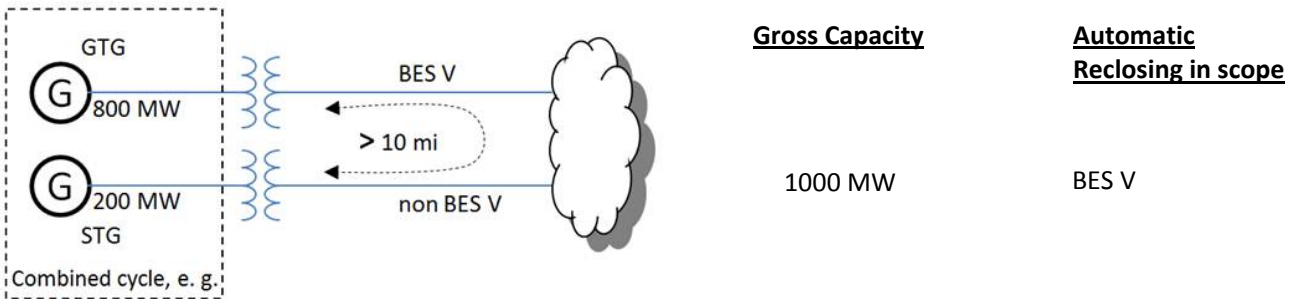
BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.

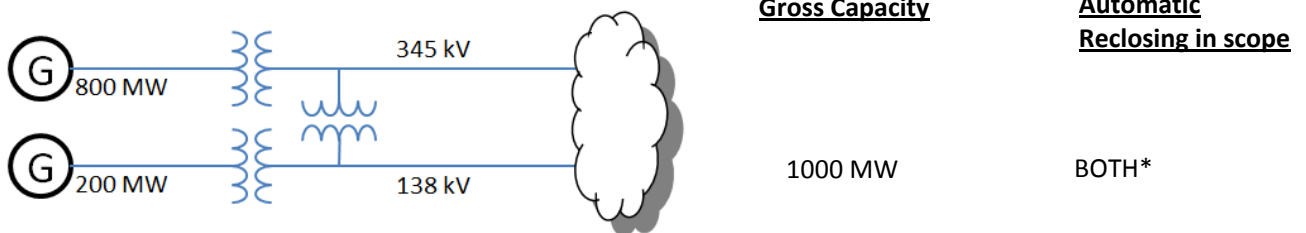


Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.6.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.6.1.



* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.6.2 specify “10 circuit miles”?

As noted in “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.6.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be “one bus away” from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. “One bus away” is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of “Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)”?

Reverse power relays are often installed to detect situations where the transmission source becomes deenergized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not ‘installed for the purpose of detecting’ these faults.

Is a Sudden Pressure Relay an auxiliary tripping relay?

No. IEEE C37.2-2008 assigns the Device No. 94 to auxiliary tripping relays. Sudden pressure relays are assigned Device No. 63. Sudden pressure relays are presently excluded from the standard because it does not utilize voltage and/or current measurements to determine anomalies. Devices that use anything other than electrical detection means are excluded. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent

with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

My mechanical device does not operate electrically and does not have calibration settings; what maintenance activities apply?

You must conduct a test(s) to verify the integrity of any trip circuit that is a part of a Protection System. This standard does not cover circuit breaker maintenance or transformer maintenance. The standard also does not presently cover testing of devices, such as sudden pressure relays (63), temperature relays (49), and other relays which respond to mechanical parameters, rather than electrical parameters. There is an expectation that Fault pressure relays and other non-electrically initiated devices may become part of some maintenance standard. This standard presently covers trip paths. It might seem incongruous to test a trip path without a present requirement to test the device; and, thus, be arguably more work for nothing. But one simple test to verify the integrity of such a trip path could be (but is not limited to) a voltage presence test, as a dc voltage monitor might do if it were installed monitoring that same circuit.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: “A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.”

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: “A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.”

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-

based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft 86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing –

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay .

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action or a Protection System Misoperation attributed to hardware

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

4.1 Frequently Asked Questions:

Why does PRC-005-3 not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-3 requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the “Tables”), and the various components of the definition established for a “Protection System Maintenance Program,” PRC-005-3 establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by “restore” in the definition of maintenance.

The description of “restore” in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity “shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.” Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by “...demonstrate efforts to correct an Unresolved Maintenance Issue...”; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and

management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase “demonstrate efforts to correct” (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a “closed-end process”). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System and Automatic Reclosing Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System and Automatic Reclosing Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers’ recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.
- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term “Condition-Based-Maintenance” (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the “monitored-basis-time-intervals” existing within the standard, the

explanatory discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

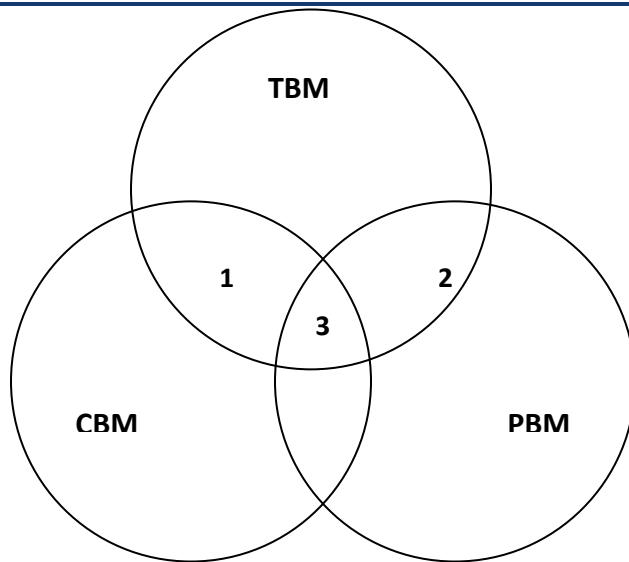
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to **ONLY** perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a “flow chart” of the standard.

We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

-
- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
 - Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

Excessive maintenance can actually decrease the reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.4) of the standard, is it necessary to

provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

“All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center.”

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

“Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability.”

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a combination of time-based and condition-based maintenance. The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-3. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-3.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a "One Calendar Year Interval," the next event would have to occur on or before December 31, 2010.

Please provide an example of "4 Calendar Months".

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May)

would still be due four months later therefore the activity is due again July. Basically every “four Calendar Months” means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions' section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

-
- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- 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 as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

-
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
 - Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Special Protection System. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, and Table 4 in the standard specify maximum allowable verification intervals for various generations of Protection Systems and Automatic Reclosing and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in [Figures 1](#) and [2](#) at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. [Figure 2](#) shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and SPS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-3:

-
- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
 - Table 1-1 is for protective relays,
 - Table 1-2 is for the associated communications systems,
 - Table 1-3 is for current and voltage sensing devices,
 - Table 1-4 is for station dc supply and
 - Table 1-5 is for control circuits.
 - Table 2, is for alarms; this was broken out to simplify the other tables.
 - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
 - Table 4 is for Automatic Reclosing.
 - Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
 - This Maintenance activity is the minimum maintenance activity that must be documented.
 - If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
 - After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
 - If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
 - Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
 - An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows

maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-3. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-3, most notable of which is an entity using performance based maintenance methodology. If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc, are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.
2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.
3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or SPS (as opposed to a monitoring task) must be verified as a component in a Protection System.
4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-3 for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-3 is a more economical approach while addressing the reliability requirements of the BES.
5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform

properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).
7. “End-to-end test,” as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.
8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.
9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by “Verify that settings are as specified” maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states “...settings are as specified.”

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require “...that the relay settings be correct...” because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have “drifted” since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the “Verify that settings are as specified” maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about SPS interfaces between different entities or owners?

As in all of the Protection System requirements, SPS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Special Protection System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the SPS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for SPS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an SPS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an SPS scheme should that occur. Forced trip tests of circuit breakers (etc) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unnecessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval, then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays

-
- Neutral overcurrent relay
 - Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A

distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-3 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or to the previous scheduled (on-site) audit date, whichever is longer.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please use a specific example to demonstrate the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld. For example: “Company A” has a maintenance plan that requires its electromechanical protective relays be tested every three calendar years, with a maximum allowed grace period of an additional 18 months. This entity would be required to maintain its records of maintenance of its last two routine scheduled tests. Thus, its test records would have a latest routine test, as well as its previous routine test. The interval between tests is, therefore, provable to an auditor as being within “Company A’s” stated maximum time interval of 4.5 years.

The intent is not to require three test results proving two time intervals, but rather have two test results proving the last interval. The drafting team contends that this minimizes storage requirements, while still having minimum data available to demonstrate compliance with time intervals.

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-3, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-3 assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-3 requires performance of maintenance activities that are deemed necessary to detect and correct plausible age and service related degradation of components, such that a properly built and commission tested Protection System will continue to function as designed over its service life.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-3 would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the “Calendar Year” language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a “grace period” without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original Protection System Maintenance – A Technical Reference in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for “time-interval extensions” or “grace periods” to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. “Maximum time intervals” by their very term negates any “time-interval extension” or “grace periods.” To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was “...no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years...” The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table’s use of the term “Calendar” in the column for “Maximum Maintenance Interval.” The PSMT SDT deemed it necessary to include the term “Calendar” to

facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term “Calendar” to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity’s use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as *ISO 9001-2000, Quality Management Systems – Requirements*; or applicable parts of the NIST Baldrige National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is “the sampling distribution of the sample mean can be approximated by a normal probability distribution.” The Central Limit Theorem states: “In selecting simple random samples of size n from a population, the sampling distribution of the sample mean \bar{x} can be approximated by a normal probability distribution as the sample size becomes large.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

“... whenever we are using a large simple random sample (rule of thumb: $n \geq 30$), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

“If samples of size n , when $n \geq 30$, are drawn from any population with a mean μ and a standard deviation σ , the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation.” (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)

“The sample size is large (generally $n \geq 30$)... (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)

“... the normal is often used as an approximation to the t distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection.” (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a “Pass/Fail” format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z \sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1 - \pi) \left(\frac{z}{B} \right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.96 \text{ (This equates to a 95\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=59.0$.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.44 \text{ (85\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=31.8$.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

Performance-Based Program Evaluation Example

The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.

In consideration of the use of Performance Based Maintenance (PBM), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval (in years) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment (units per year), or any misoperation attributable to hardware failure or calibration failure found within the entire segment (1000 units) during the testing year.

Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: $125 \times .04 = 5$. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations (attributable to hardware or calibration failure within the testing year) associated with the entire segment of 1000 units.

Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: $63 \times .04 = 2.5$.

As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.

Total number of units in the segment	1000
Failure rate	4.00%

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

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.

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.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

9.2 Frequently Asked Questions:

I’m a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect

to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure rate (zero failures) while Type "Y" would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment performance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, “reset the clock” on everything you’ve done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that “resetting the clock” should not be construed as interfering with an entity’s routine testing schedule because the “clock-reset” would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is

allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that “replaced relay” will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. $6/200 = 3\%$ failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. $6/100 = 6\%$ failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year ($1000/8$). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. $6/125 = 5\%$ failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year ($1000/7$). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. $6/143 = 4.2\%$ failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year ($1000/6$). After a year, they again find six failures out of the 167 units tested. $6/167 = 3.6\%$ failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures “Control Circuitry” as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity’s specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device

that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year ($1000/12$). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures “voltage and current inputs to the protective relays” as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a “Relay Scheme.” Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT’s or specific PT’s. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 2000 “Relay Schemes,” all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT’s. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity’s relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their “Voltage and Current Sensing” population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested ($U = P/I$)	# of Failures Found (F)	Failure Rate ($=F/U$)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays “that are designed to provide protection for the BES,” this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its

regularly scheduled cycle. (However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays “out-of-service”. What are our responsibilities when it comes to “out-of-service” devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-3 are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-3. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-3 to remove such component(s). Obviously, prudence would dictate that an “out-of-service” device is truly made inactive. There are no record requirements listed in PRC-005-3 for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-3 requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-3 requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

“R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.”

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state “...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues...” The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-3 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

These relays are defined as the devices that receive the input signal from the current and voltage sensing devices and are used to isolate a Faulted Element of the BES. Devices that sense thermal, vibration, seismic, pressure, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
 - There is no specific protective relay commissioning test or relay routine test mandated.
 - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the

protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and vars around the entire bus; this should add up to zero watts and zero vars, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "...verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ..." Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay

and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor-based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately “verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ...” while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "...designed to provide protection for the BES..." then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

While relays that do not respond to electrical quantities are presently excluded from this standard, their control circuits are included if the relay is installed to detect Faults on BES Elements. Thus, the control circuit of a BES transformer sudden pressure relay should be verified every 12 years, assuming its integrity is not monitored. While a sudden pressure relay control circuit is included within the scope of PRC-005-2, other alarming relay control circuits, (i.e., SF-6 low gas) are not included, even though they may trip the breaker being monitored.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes

that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-3 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-3 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-3 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.

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- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-3 applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have an non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- 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.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, “station batteries” are replaced with “station dc supply” to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-3 is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by “continuity” of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.

- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the

station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example “Conductance Readings” from one manufacturer’s test equipment do not correlate to “Impedance Readings” from a different manufacturer’s test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity

readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries).

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery

containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance “as designed” vs. battery performance “as manufactured.” The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer’s rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trendline against the established baseline. The type of probe and its location (post, connector, etc) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measurable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be “forming” after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an "adequate" ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one

minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-3 is there a maintenance activity to inspect the structural integrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.

Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the “Unintentional dc Grounds” requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a “check-off” of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to “all cells,” is it sufficient to have a documentation method that refers to “all cells,” or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-3 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980’s several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery’s current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The

inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "...depending on the degree of change a performance test, cell replacement or other corrective action may be necessary..." (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or

above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid 1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically

trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to “measure battery cell/unit internal ohmic values.” Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is “...verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline.” This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to “Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.”

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to ‘perform as manufactured.’ It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the “perform as manufactured six-month test” at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the “thermal runaway test” at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float

(charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to “verify station dc supply voltage” every “4 calendar months” (see table 1-4(a)), the owner can install a monitoring and alarming device “with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure” and “no periodic verification of station dc supply voltage is required” (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install “electrolyte level monitoring and alarming in every cell” and “unintentional dc ground monitoring and alarming” (see second and third rows of table 1-4(f)), the owner will have to “inspect electrolyte level and for unintentional grounds” every “4 calendar months” (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to “Protection System Control Circuitry”, rather than those portions of the table applicable to communications equipment.

What is meant by “Channel” and “Communications Systems” in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the “channel” as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting “performance criteria.” What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These

limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe “form-b” contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "...does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature autoreclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage

supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that is not part of an SPS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that is part of an SPS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the SPS, and must be verified.

15.9 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.9.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics

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- Maintenance records
 - Logs (operator, substation, and other types of log)
 - Inspection forms
 - Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
 - Check-off forms (paper or electronic)
 - Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 (“Special Protection System Misoperation”). Can I also use it to show compliance for this Standard, PRC-005-3?

Maintaining evidence for operation of Special Protection Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-3.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

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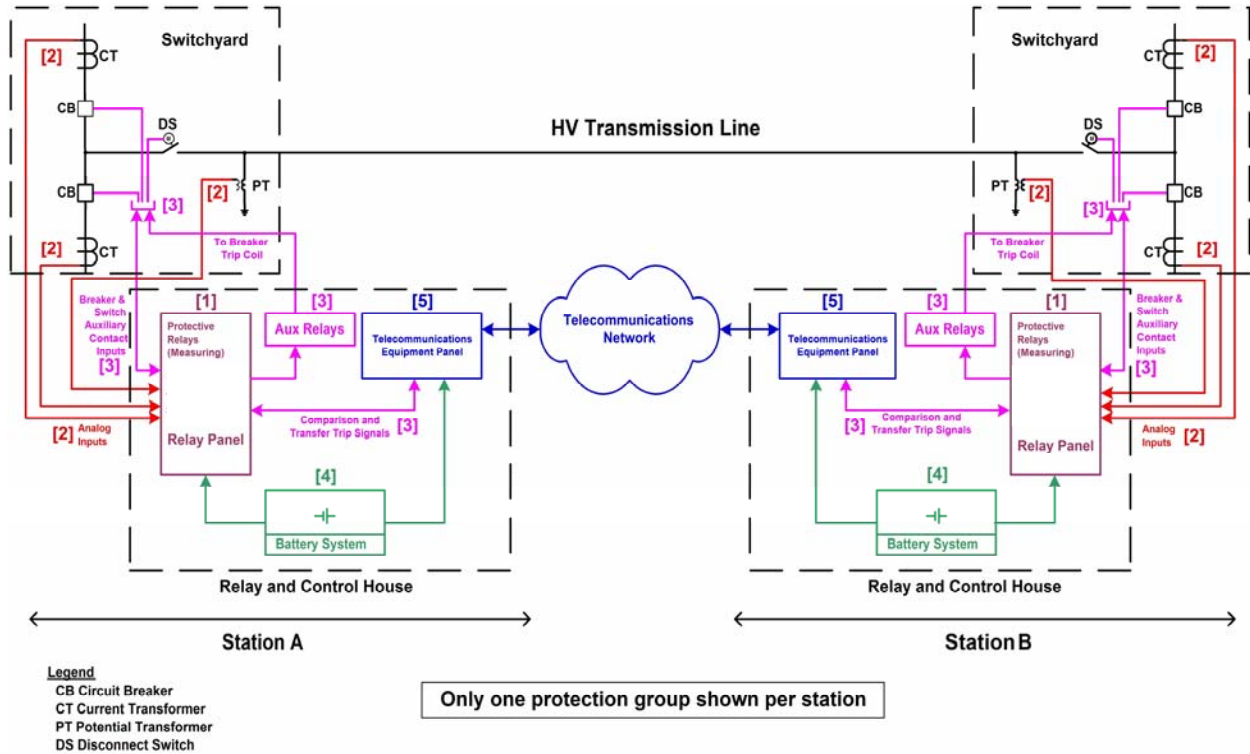
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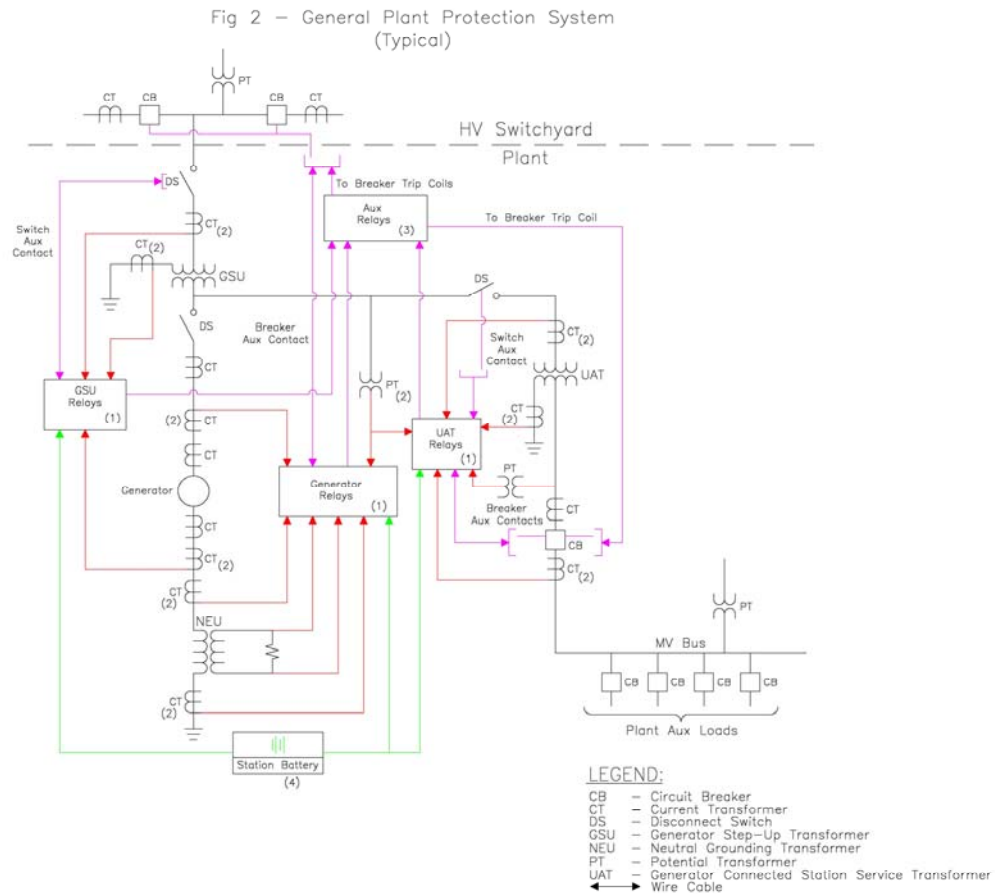
Figures

Figure 1: Typical Transmission System



For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 1 & 2 Legend – Components of Protection Systems

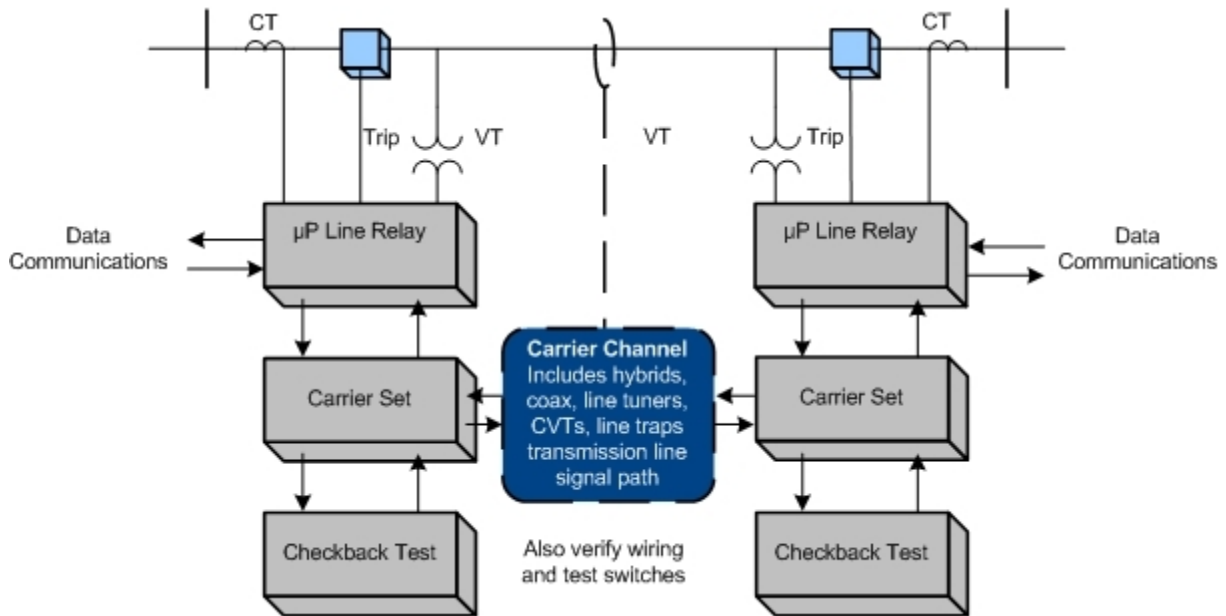
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

[Additional information can be found in References](#)

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line faults, and to avoid over-tripping for faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



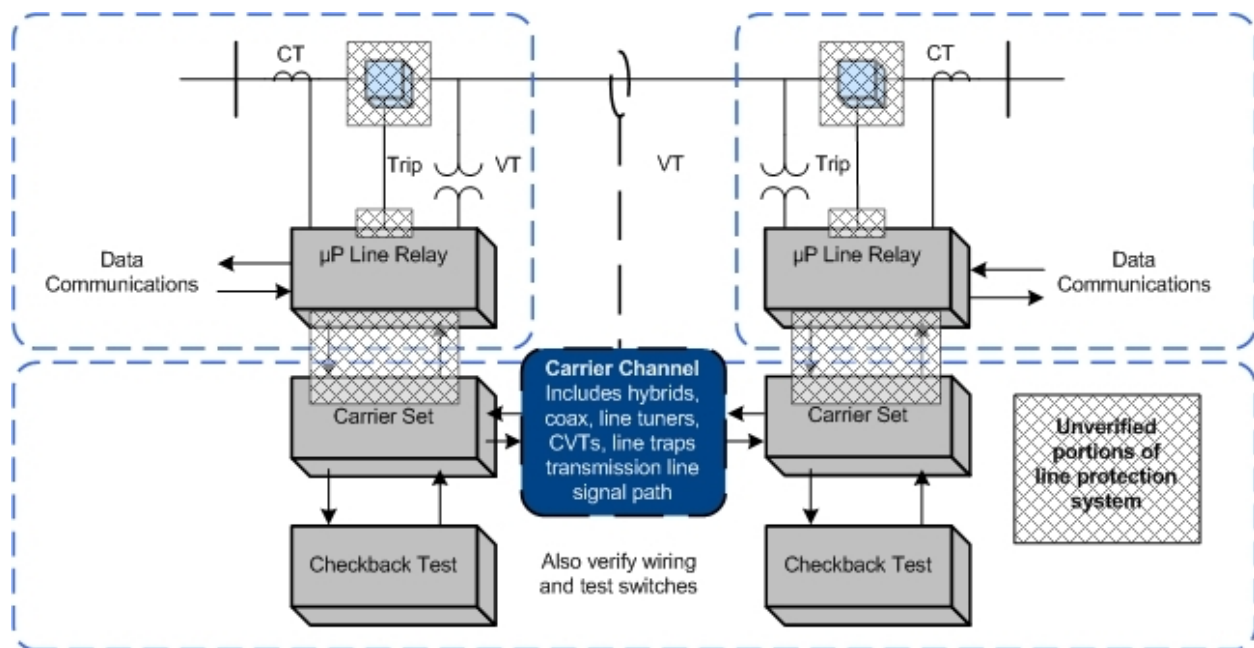
In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.
2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the

contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.

3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-3 does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

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Exhibit F

Table of Issues and Directives

Table of Issues and Directives

Project 2007-17.2 PRC-005-3

Protection System and Automatic Reclosing Maintenance

Table of Issues and Directives Associated with PRC-005-3

Source	Directive Language (including pg #)	Disposition	Section and/or Requirement(s)
FERC Order 758	27. We note that the original project to revise Reliability Standard PRC-005 failed a recirculation ballot in July of 2011. The project was subsequently reinitiated to continue the efforts to develop Reliability Standard PRC-005-2. Given that the project to draft proposed revisions to Reliability Standard PRC-005-1 continues in this reinitiated effort, and the importance of maintaining and testing reclosing relays, we direct NERC to include maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System, as discussed above, within these reinitiated efforts to revise Reliability Standard PRC-005.	Specific minimum activities and maximum allowable intervals are included in the draft standard within Table 4.	Applicability 4.2.6 Requirement R1, R3, Requirement R4, Table 4

Exhibit G

Analysis of Violation Risk Factors and Violation Security Levels

Violation Risk Factor and Violation Severity Level Justifications

Project 2007-17.2 PRC-005-3

Protection System and Automatic Reclosing Maintenance

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-005-2 - Protection System Maintenance.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Maintenance and Testing Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria – VRFs

High Risk Requirement

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

Medium Risk Requirement

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

Lower Risk Requirement

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

FERC VRF Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC’s Definition of the VRF Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC’s definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC’s VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC’s Reliability Standards and implies that these requirements should be assigned a “High” VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

PRC-005-3 Protection System and Automatic Reclosing Maintenance is a revision of PRC-005-2 Protection System Maintenance with the stated purpose: To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

PRC-005-3 has five (5) requirements that address the inclusion of Automatic Reclosing. A Table of minimum maintenance activities and maximum maintenance intervals has been added to PRC-005-2 to address FERC’s directives from Order 758. The revised standard requires that entities develop an appropriate Protection System Maintenance Program (PSMP), that they implement their PSMP, and that, in the event they are unable to restore Automatic Reclosing Components to proper working order while performing maintenance, they initiate the follow-up activities necessary to resolve those maintenance issues.

The requirements of PRC-005-3 map one-to-one with the requirements of PRC-005-2. The drafting team did not revise the VRFs for the requirements of PRC-005-3.

PRC-005-3 Requirements R1 and R2 are related to developing and documenting a Protection System Maintenance Program. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violations of these requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

PRC-005-3 Requirements R3 and R4 are related to implementation of the Protection System Maintenance Program. The SDT determined that the assignment of a VRF of High was consistent with the NERC criteria that that violation of these requirements could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are assigned a VRF of High.

PRC-005-3 Requirement R5 relates to the initiation of resolution of unresolved maintenance issues, which describe situations where an entity was unable to restore a Component to proper working order during the performance of the maintenance activity. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violation of this requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

NERC Criteria - VSLs

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
<p>Missing a minor element (or a small percentage) of the required performance</p> <p>The performance or product measured has significant value as it almost meets the full intent of the requirement.</p>	<p>Missing at least one significant element (or a moderate percentage) of the required performance.</p> <p>The performance or product measured still has significant value in meeting the intent of the requirement.</p>	<p>Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital Component.</p> <p>The performance or product has limited value in meeting the intent of the requirement.</p>	<p>Missing most or all of the significant elements (or a significant percentage) of the required performance.</p> <p>The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.</p>

FERC Order on VSLs

In its June 19, 2008 Order on VSLs, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

- Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

- Guideline 2a: A violation of a “binary” type requirement must be a “Severe” VSL.
- Guideline 2b: Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: VSL Assignment Should Be Consistent with the Corresponding Requirement

- VSLs should not expand on what is required in the requirement.

Guideline 4: VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

- . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF and VSL Justifications

VRF and VSL Justifications – PRC-005-3, R1	
Proposed VRF	Medium
NERC VRF Discussion	Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so only one VRF was assigned. The requirement utilizes Parts to identify the items to be included within a Protection System Maintenance Program. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-2 Requirement R1.

VRF and VSL Justifications – PRC-005-3, R1			
Proposed VRF	Medium		
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs:</p> <p>Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:</p> <p>This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.</p>		
Proposed VSL – PRC-005-3, R1			
Lower	Moderate	High	Severe
<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p>OR</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p>OR</p>	<p>The responsible entity failed to establish a PSMP.</p> <p>OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>

Proposed VSL – PRC-005-3, R1			
Lower	Moderate	High	Severe
The responsible entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1)		The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	

VRF and VSL Justifications – PRC-005-3, R1	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R1

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R2	
Proposed VRF	Medium
NERC VRF Discussion	Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-2 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for.

VRF and VSL Justifications – PRC-005-3, R2			
Proposed VRF	Medium		
	Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-3, R2			
Lower	Moderate	High	Severe
The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	N/A	The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP

Proposed VSL – PRC-005-3, R2			
Lower	Moderate	High	Severe
			<p>OR</p> <p>2) Failed to reduce countable events to no more than 4% within five years</p> <p>OR</p> <p>3) Maintained a Segment with less than 60 Components</p> <p>OR</p> <p>4) Failed to:</p> <ul style="list-style-type: none"> • Annually update the list of Components, <p>OR</p> <ul style="list-style-type: none"> • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, <p>OR</p> <ul style="list-style-type: none"> • Annually analyze the program activities and results for each Segment.

VRF and VSL Justifications – PRC-005-3, R2	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R2

Guideline 2b: VSL Assignments that Contain Ambiguous Language	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R3	
Proposed VRF	High
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-3, R3			
Lower	Moderate	High	Severe
For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2.

VRF and VSL Justifications – PRC-005-3, R3

<p>NERC VSL Guidelines</p>	<p>Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.</p>
<p>FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.</p>
<p>FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: N/A</p> <p>Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – PRC-005-3, R3

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R4	
Proposed VRF	High
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-3, R4			
Lower	Moderate	High	Severe
For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.

VRF and VSL Justifications – PRC-005-3, R4	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R4

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R5	
Proposed VRF	Medium
NERC VRF Discussion	Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only requirement within approved Standards, PRC-004-2a Requirements R1 and R2 contain a similar requirement and is assigned a HIGH VRF. However, these requirements contain several subparts, and the VRF must address the most egregious risk related to these subparts, and a comparison to these requirements may be irrelevant. PRC-022-1 Requirement R1.5 contains only a similar requirement, and is assigned a MEDIUM VRF. FAC-003-2 Requirement R5 contains only a similar requirement, and is assigned a MEDIUM VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system.

VRF and VSL Justifications – PRC-005-3, R5			
Proposed VRF	Medium		
	<p>However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.</p>		
Proposed VSL – PRC-005-3, R5			
Lower	Moderate	High	Severe
The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

VRF and VSL Justifications – PRC-005-3, R5	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirement in PRC-005-2 has not been implemented; consequently, there is no prior level of compliance.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R5

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Exhibit H

Summary of Development History and Complete Record Development

**Exhibit H — Summary of Development History and Complete Record of Development —
Proposed Reliability Standard PRC-005-3**

The development record for proposed Reliability Standard PRC-005-3 is summarized below.

I. Overview of the Standard Drafting Team

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

II. Standard Development History

A. Standard Authorization Request Development

A Standard Authorization Request (“SAR”) was approved by the Standards Committee (“SC”) on January 17, 2013 and posted for a 30-day public comment period from April 5, 2013 through May 6, 2013. There were 24 sets of responses, including comments from approximately 93 individuals from approximately 64 companies representing 8 of the 10 industry segments. Commenters agreed that the scope of the SAR adequately addressed the Commission’s directive in Order No. 758.

B. First Posting

Proposed Reliability Standard PRC-005-3 was posted for a 30-day public comment period from April 5, 2013 through May 6, 2013. There were 36 sets of responses, including comments from approximately 143 individuals from approximately 95 companies representing 8 of the 10 industry segments.

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

The standard drafting team considered stakeholder comments and made the following changes to proposed Reliability Standard PRC-005-3 based on those comments:

To the Definitions:

- Protection System Maintenance Program (PSMP):
 - Un-capitalized the term “Automatic Reclosing”
- Automatic Reclosing
 - Minor revisions to provide clarity:
 - Includes the following Components:
 - Reclosing relay
 - Control circuitry associated with the reclosing relay.
- Segment
 - Capitalized the defined term “Component”
- Countable Event
 - Updated to incorporate reference to new Tables 4-1 through 4-2, and added the term “Protection System” as a modifier of Misoperation for clarity.

To the Applicability:

- To add clarity, the drafting team revised 4.2.6 Facilities and each of the sections: 4.2.6.1, 4.2.6.2. and 4.2.6.3. The associated footnote was modified for congruence with the referenced sections.

To the Requirements:

- The Table reference in Requirement R1, Part 1.2 was updated to include Tables 4-1 through 4-2, and the wording was revised for clarity.
- The Table reference in Requirement R3 was updated to include Tables 4-1 through 4-2.

To the Measures:

- The Table reference in Measure M1 was updated to include Tables 4-1 through 4-2.

To the Compliance Section:

- The drafting team added the phrase “or Automatic Reclosing” for clarity.

To the VSLs:

- The Table references in the VSLs were updated to include Tables 4-1 through 4-2.

To the Version History:

- The previous version history of PRC-005 was added for completeness.

To the Tables:

- The Tables were updated to accommodate the addition of Tables 4-1 through 4-2.

To Attachment A:

- Attachment A was updated to include Tables 4-1 through 4-2.

To the *Supplementary Reference and FAQ* document:

- Additional content was added to reflect changes in the standard.

Additional Implementation Plan:

- A second Implementation Plan was developed to address generation changes in the Balancing Authority Area that result in additional locations becoming subject to the Applicability of PRC-005-3. The document titled: “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area”, was posted with the draft standard.

Unresolved Minority Views:

- Several commenters suggested making general changes to PRC-005-2. The drafting team responded that the SAR precludes the drafting team from making general revisions to the standard in content or arrangement, only allowing modifications to explicitly address the maintenance and testing of reclosing relays which can affect the reliable operation of the Bulk Electric System. The drafting team did not make any of the suggested changes.
- Several commenters were concerned about initiating the project to establish PRC-005-3 before PRC-005-2 is FERC approved. The drafting team explained that they are acting in accordance with the schedule provide to FERC in an informational filing submitted by NERC, in response to FERC Order 758 which stated: “By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.” In the Order, FERC accepted NERC’s commitment to address the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System within the standards development process. Phase 2 (Reclosing Relays) of Project 2007-17 Protection System Maintenance and Testing was initiated to develop PRC-005-3 and satisfy NERC’s commitment to the FERC.
- A few commenters questioned the complexity of the Implementation Plan for PRC-005-3 which includes the Protection System aspects of PRC-005-2 and adds the new aspects of Automatic Reclosing from PRC-005-3. The plan addresses the implementation of the PRC-005-2 requirements based on the approval date of PRC-005-2 and adds the implementation of the revised requirements that include Automatic Reclosing based on the approval date of PRC-005-3. This approach provides clarity regarding the implementation dates for maintenance of Protection System and Automatic Reclosing Components. The drafting team crafted the Implementation Plan with guidance from NERC legal staff and believes the Implementation Plan is clear once carefully reviewed.

C. Second Posting

Proposed Reliability Standard PRC-005-3 was posted for a 45-day public comment and ballot period from July 10, 2013 through August 23, 2013. There were 41 sets of responses, including comments from approximately 149 individuals from approximately 85 companies

representing 7 of the 10 industry segments. Proposed Reliability Standard PRC-005-3 received a quorum of 78.33% and an approval 79.24%.

The standard drafting team considered stakeholder comments and made the following changes to the Implementation Plan based on those comments:

To the Implementation Plan:

- In response to comments, the drafting team incorporated the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area” into the full Implementation Plan to consolidate the implementation documents. Numerous commenters disagreed with the implementation period specified in the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area” stating that it was too short to accommodate the potential number of newly identified Automatic Reclosing Components that could become applicable nor did it provide enough time for potential outage coordination(s) necessary to perform the required maintenance. Upon reconsideration, the drafting team agreed that the proposed implementation schedule for newly identified Automatic Reclosing Components was inappropriate and could potentially jeopardize reliability by forcing entities to take unscheduled outages to become compliant. The drafting team deemed three years to be sufficient to avoid the reliability concerns and permit entities to implement maintenance in a manner that would be sustainable in the long-term.
- In response to a comment, the drafting team inserted the jurisdictional pro-forma language where it had been inadvertently left out of the Implementation Plan. Additionally, NERC will file the errata change with the applicable regulatory authorities as necessary for the PRC-005-2 Implementation Plan.
- To avoid confusion, the drafting team modified paragraph 4 of the Background section to remove the references to the implementation timing. The timing is already comprehensively addressed in the implementation plan for each requirement.

To the Supplementary Reference and FAQ Document:

- Additional content was provided to improve the reference document.

Unresolved Minority Views:

- A few commenters objected to the development of PRC-005-3 prior to regulatory approval of PRC- 005-2. The drafting team advised that they are acting in accordance with the schedule NERC provided to FERC which outlines the timeframes in which NERC will respond to the directives of FERC Order 758 through the standards drafting process. Specifically regarding reclose relays (Footnote 37), FERC directed NERC to: “By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing

that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.”

- Several commenters requested an additional requirement be included in PRC-005-3 mandating that Balancing Authorities provide Transmission Owners, Generator Owners, and Distribution Providers the information identifying the current largest single generating unit in the Balancing Authority Area (described in Applicability 4.2.6), and notify those entities (within a specified time) when this information changes. The SAR for this project does not permit the addition of functional entities to the Applicability section of this standard; therefore, the drafting team is unable to make the requested change. The drafting team understood the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised.

D. Final Ballot

Proposed Reliability Standard PRC-005-3 was posted for a 10-day final ballot period from October 16, 2013 through October 25, 2013. The proposed Reliability Standard received a quorum of 85.71% and an approval rating of 85.38%.

E. Board of Trustees Approval

Proposed Reliability Standard PRC-005-3 was approved by the NERC Board of Trustees on November 7, 2013.

Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)

Related Files

Status:

PRC-005-3 was adopted by the NERC Board of Trustees at its November 7, 2013 meeting.

Background:

On February 3, 2012, the Federal Energy Regulatory Commission (FERC) issued Order No. 758 approving an interpretation of NERC Reliability Standard PRC-005-1, Transmission and Generation Protection System Maintenance and Testing. In addition to approving the interpretation, the Commission directed that concerns identified in the preceding Notice of Proposed Rulemaking (NOPR) be addressed within the reinitiated PRC-005 revisions. The concerns raised in the NOPR pertain to automatic reclosing (autoreclosing) relays that are either "used in coordination with a Protection System to achieve or meet system performance requirements established in other Commission-approved Reliability Standards, or can exacerbate fault conditions when not properly maintained and coordinated," in which case "excluding the maintenance and testing of reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the Bulk-Power System." To address these concerns, the Commission concludes that "specific requirements or selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System."

In response to Order No. 758, the Protection System Maintenance and Testing Standard Drafting Team (SDT) drafted a Standard Authorization Request (SAR) to modify PRC-005 to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System. On May 10, 2012, the NERC Standards Committee (SC) accepted the SAR and authorized that it be posted for information only along with the 3rd draft of PRC-005-2. The NERC SC noted that PRC-005-2 was in the final stages of the development process, having passed a successive ballot with 79 percent approval on June 27, 2012 and was scheduled to be presented for approval at the November NERC Board of Trustees meeting. Consequently, in recognition of the consensus achieved, the NERC SC determined that the drafting team should complete the development of PRC-005-2 and immediately thereafter begin work on PRC-005-3 which would reflect the necessary revisions to address reclosing relays.

The SDT also requested the NERC Planning Committee (PC) provide the technical input necessary to develop the appropriate revisions to PRC-005. The NERC PC instructed the NERC System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) to jointly perform a technical study to determine which reclosing relays should be addressed within PRC-005 and provide advice regarding the appropriate maintenance intervals and activities for those relays. The final report was approved by the NERC PC on November 14, 2012 and provided to the SDT for guidance in developing PRC-005-3.

In Order No. 758, the Commission also directed NERC to file, by July 30, 2012, either a completed project, or an informational filing providing "a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts." On July 30, 2012, NERC submitted an informational filing in compliance with Order No. 758 with a proposed schedule for addressing reclosing relays. The project number and name are as follows: Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays).

On January 17, 2013 the NERC SC authorized the draft SAR to be posted for industry comment and on April 4, 2013, the SC authorized the standard to be posted for a 30-day comment period.

Draft	Action	Dates	Results	Consideration of Comments
<p>PRC-005-3 Clean (41) Redline to Last Posted (42)</p> <p>Redline to Last Approved (43)</p> <p>Implementation Plan Clean (44) Redline to Last Posted (45)</p> <p>Supporting Materials:</p> <p>Supplementary Reference and FAQ Clean (46) Redline to Last Posted (47)</p>	<p>Final Ballot</p> <p>Info>> (48)</p> <p>Vote>></p>	<p>10/16/13 - 10/25/13 (Closed)</p>	<p>Summary>> (49)</p> <p>Ballot Results>> (50)</p>	
<p>PRC-005-3 Clean (21) Redline to Last Posted (22)</p> <p>Implementation Plan Clean (23) Redline to Last Posted (24)</p> <p>Implementation Plan for Newly Identified</p>	<p>Ballot and Non-binding Poll Updated Info>> (34)</p> <p>Vote>></p> <p>Comment Period Info>> (35)</p>	<p>08/14/13 - 08/23/13 (Closed)</p> <p>07/10/13 - 08/23/13 (Closed)</p>	<p>Summary>> (36)</p> <p>Ballot Results>> (37)</p> <p>Non-binding Poll>> (38)</p>	<p>Consideration of Comments>> (40)</p>

<p>Automatic Reclosing Components (25)</p> <p>Supporting Materials: Unofficial Comment Form (Word) (26)</p> <p>SAR Clean (27) Redline to Last Posted (28)</p> <p>VRF/VSL Justification Clean (29) Redline to Last Posted (30)</p> <p>Supplementary Reference and FAQ Clean (31) Redline to Last Posted (32)</p> <p>Table of Issues and Directives (33)</p>	<p>Submit Comments>></p> <p>Join Ballot Pool>></p>	<p>07/10/13 - 08/08/13 (Closed)</p>	<p>Comments Received>> (39)</p>	
<p>Draft SAR (1)</p> <p>PRC-005-3 Clean (2) Redline to Last Approved (3)</p> <p>Supporting Materials: Unofficial Comment Form (Word): Draft SAR (4) PRC-005-3 (5)</p> <p>Implementation Plan Clean (6) Redline to Last Approved (7)</p> <p>VRF/VSL Justification Clean (8) Redline to Last Approved (9)</p>	<p>Comment Period</p> <p>Info>> (16)</p> <p>Submit Comments: Draft SAR PRC-005-3</p>	<p>04/05/13 - 05/06/13 (Closed)</p>	<p>Comments Received Draft SAR>> (17)</p> <p>PRC-005-3>> (18)</p>	<p>Consideration of Comments Draft SAR>> (19)</p> <p>PRC-005-3>> (20)</p>

Supplementary Reference and FAQ Clean (10) Redline to Last Approved (11)				
Table of Issues and Directives (12)				
FERC Order 758 (13)				
Informational Filing in Compliance with Order No. 758 (14)				
SAMS-SPCS Order 758 Autoreclosing Report (15)				

E-mail completed form to
sarcomm@nerc.com

Standard Authorization Request Form

Request Date January 17, 2013

SAR Requester Information	SAR Type (Check a box for each one that applies.)	
Individual, Group, or Committee Name Protection System Maintenance Standard Drafting Team	<input type="checkbox"/>	New Standard
Primary Contact (if Group or Committee) Charles Rogers	<input checked="" type="checkbox"/>	Revision to existing Standard
Company or Group Name Chairman, Protection System Maintenance Standard Drafting Team	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail Charles.Rogers@cmsenergy.com	<input type="checkbox"/>	Project Identified in Reliability Standards Development Plan (Project Number and Name:)
Telephone 517-788-0027	<input checked="" type="checkbox"/>	Modification to NERC Glossary term or addition of new term

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Brief Description of Proposed Standard Modifications/Actions (In three sentences or less, summarize the proposed actions a drafting team will be responsible for implementing.)

The Standard Drafting Team shall modify NERC Standard PRC-005-2 to explicitly address the maintenance and testing of reclosing relays which can affect the reliable operation of the Bulk Electric System.

The Standard Drafting Team shall not make general revisions to the standard in content or arrangement.

Need (Explain why the Standard is being developed or modified. Clearly indicate why the actions being proposed are needed for maintaining or improving bulk power system reliability, including an assessment of the reliability and market interface impacts. This is similar to the Purpose statement in a Reliability Standard.)

Reclosing relays are applied to facilitate automatic restoration of system components following a Protection System operation. In certain circumstances the misoperation of reclosing relays can impact the reliability of the Bulk Electric System. The Federal Energy Regulatory Commission, in paragraphs 16-27 of Order No. 758, directed that NERC include reclosing relays that “can affect the reliable operation of the Bulk-Power System” within NERC Standard PRC-005

Modifying the standard in this fashion will impact Bulk Electric System (BES) reliability by assuring that the reclosing relays (installed to meet performance goals of approved NERC Standards) are properly maintained so that they may be expected to perform properly.

No market interface impacts are anticipated.

Goals (Describe what must be accomplished in order to meet the above need. This section would become the Requirements in a Reliability Standard.)

The revision to PRC-005-2 may require that the definition of Protection System be revised to add reclosing relays.

The Applicability section of the Standard must be modified to describe explicitly those devices that entities are to maintain in accordance with the revised standard.

The Tables of minimum maintenance activities and maximum maintenance intervals will require modification to include appropriate intervals and activities.

Finally, the informative Supplementary Reference Document (provided as a technical reference for PRC-005-2) should be modified to provide the rationale for the maintenance activities and intervals within the modified standard, as well as to provide application guidance to industry.

Objectives and/or Potential Future Metrics (Describe what the potential measure or criteria for success may be for determining the successful implementation of this request. Provide ideas for potential metrics to be developed and monitored in the future relative to this request, if any.)

Successful implementation of the modified standard will assure that the devices being added will perform as needed for the conditions anticipated by those performance requirements.

Detailed Description (In three paragraphs or more, provide a detailed description of the proposed actions a drafting team will be responsible for executing so that the team can efficiently implement this request. While you will check applicability boxes on the following page, this description must include proportional identification of to whom the standard should apply among industry participants.)

The drafting team shall:

1. Consider revision of the title of the Standard to appropriately address the added devices.
2. Modify the Purpose of the Standard as necessary to address reclosing relays.
3. Consider modification of the definition of Protection System to add reclosing relays.
4. Modify the Applicability section of PRC-005-2 to describe explicitly those devices that entities are to maintain in accordance with the revised standard.
5. Modify the Tables within PRC-005-2 to include maximum intervals and minimum activities appropriate for the devices being addressed, with consideration for the technology of the devices and for any condition monitoring that may be in place for those devices.
6. Modify the Measures and Violation Severity Levels as necessary to address the modified requirements.
7. Modify the informative Supplementary Reference Document (provided as a technical reference for PRC-005-2) to provide the rationale for the maintenance activities and intervals within the modified standard, as well as to provide application guidance to industry.

OPTIONAL: Technical Analysis Performed to Support Justification (Provide the results of any technical study or analysis performed to justify this request. Alternatively, if deemed necessary, propose a technical study or analysis that should be performed prior to a related standard development project being initiated in response to this request.)

The NERC System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) have jointly performed a technical study to determine which reclosing relays should be addressed within PRC-005 and provide advice regarding appropriate maintenance intervals and activities for those relays. The related report was approved by the NERC Planning Committee on November 14, 2012.

The Standard Drafting Team shall use this report as an aid in developing appropriate revisions to PRC-005-2.

Reliability Functions

The Standard(s) May Apply to the Following Functions <i>(Check box for each one that applies.)</i>		
<input type="checkbox"/>	Regional Entity	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
<input type="checkbox"/>	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
<input type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/>	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/>	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/>	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
<input type="checkbox"/>	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
<input type="checkbox"/>	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input checked="" type="checkbox"/>	Transmission Owner	Owens and maintains transmission facilities.
<input type="checkbox"/>	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input checked="" type="checkbox"/>	Distribution Provider	Delivers electrical energy to the End-use customer.
<input checked="" type="checkbox"/>	Generator Owner	Owens and maintains generation facilities.
<input type="checkbox"/>	Generator Operator	Operates generation unit(s) to provide real and reactive power.

<input type="checkbox"/>	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/>	Market Operator	Interface point for reliability functions with commercial functions.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles <i>(Check box for all that apply.)</i>	
<input checked="" type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input checked="" type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
Does the proposed Standard(s) comply with all of the following Market Interface Principles? <i>(Select 'yes' or 'no' from the drop-down box.)</i>	
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	

- | |
|--|
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.
Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

Related Standards

Standard No.	Explanation
NONE	

Related Projects

Project ID and Title	Explanation
NONE	

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standard Development Roadmap

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

Development Steps Completed:

1. Standards Committee approved posting SAR and draft standard on January 17, 2013.
2. SAR posted for 30-day informal comment period from April 5, 2013 through May 6, 2013.
3. Draft 1 of PRC-005-3 posted for a 30-day formal comment period from April 5, 2013 through May 6, 2013.

Description of Current Draft:

This is the first draft of the PRC-005-3. The standard modifies PRC-005-2 to address the directive issued by the Federal Energy Regulatory Commission in Order No.758 for “NERC to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System...”

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for 30-day formal comment	April 2013
2. Post for a concurrent 45-day comment and initial ballot	June 2013
3. Conduct recirculation ballot	August 2013

Definitions of Terms Used in Standard

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

Protection System Maintenance Program (PSMP) (NERC Board of Trustees Approved

Definition) — An ongoing program by which Protection System and Automatic Reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

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

Automatic Reclosing –

- Reclosing relay
- Control circuitry associated with the reclosing relay through the close coil(s) of the circuit breakers or similar device but excluding breaker internal controls such as anti-pump and various interlock circuits.

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

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Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

A. Introduction

- 1. Title:** **Protection System and Automatic Reclosing Maintenance**
- 2. Number:** PRC-005-3
- 3. Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
- 4. Applicability:**
 - 4.1. Functional Entities:**
 - 4.1.1** Transmission Owner
 - 4.1.2** Generator Owner
 - 4.1.3** Distribution Provider
 - 4.2. Facilities:**
 - 4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4** Protection Systems installed as a Special Protection System (SPS) for BES reliability.
 - 4.2.5** Protection Systems for 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 for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
 - 4.2.6** Automatic Reclosing¹
 - 4.2.6.1** Applied on BES Elements at generating plant substations where the total installed generating plant capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area.

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 generation in the Interconnection exceeding the largest unit within the Balancing Authority Area where the Automatic Reclosing is applied.

4.2.6.2 Applied on 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 Applied as an integral part of a SPS specified in Section 4.2.4.

Component Type - Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

5. Effective Date: See Implementation Plan

B. Requirements

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

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System Component Type and Automatic Reclosing Components consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

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

- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

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.

C. Measures

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

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4. (Part 1.2)

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

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

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification

Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.3. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

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

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 3) Maintained a Segment with

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				less than 60 Components OR 4) Failed to: <ul style="list-style-type: none"> • Annually update the list of Components, <li style="text-align: center;">OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, <li style="text-align: center;">OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based

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

E. Regional Variances

None

F. Supplemental Reference Document

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

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

Version History

Version	Date	Action	Change Tracking
2	November 2012	Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0	Complete revision
3	TBD	Revision to include Automatic Reclosing into existing Version	Inclusion of Automatic Reclosing only

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

² For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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.

<p align="center">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)</p>		
<p align="center">Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

<p align="center">Table 1-4(b)</p> <p align="center">Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries</p> <p align="center">Excluding distributed UFLS and distributed UVLS (see Table 3)</p>		
<p align="center">Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

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

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS.	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, and Table 4 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Table 4 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: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2). 	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4 Maintenance Activities and Intervals for Automatic Reclosing Components		
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: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). 	12 Calendar Years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Unmonitored Control circuitry associated with Automatic Reclosing including the close coil.	12 Calendar Years	Verify the Automatic Reclosing control path including the close coil.
Control circuitry associated with Automatic Reclosing including the close coil whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

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

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

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Table 4 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – *Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.*

Countable Event – *A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.*

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

1. At least annually, update the list of 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.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Standard Development Roadmap

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

Development Steps Completed:

1. Standards Committee approved posting SAR and draft standard on January 17, 2013.
2. SAR posted for 30-day informal comment period from April 5, 2013 through May 6, 2013.
3. Draft 1 of PRC-005-3 posted for a 30-day formal comment period from April 5, 2013 through May 6, 2013.

Description of Current Draft:

This is the first draft of the PRC-005-3. The standard modifies PRC-005-2 to address the directive issued by the Federal Energy Regulatory Commission in Order No.758 for “NERC to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System...”

Future Development Plan:

<u>Anticipated Actions</u>	<u>Anticipated Date</u>
<u>1. Post for 30-day formal comment</u>	<u>April 2013</u>
<u>2. Post for a concurrent 45-day comment and initial ballot</u>	<u>June 2013</u>
<u>3. Conduct recirculation ballot</u>	<u>August 2013</u>

Definitions of Terms Used in Standard

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

Protection System Maintenance Program (PSMP) (NERC Board of Trustees Approved Definition) — An ongoing program by which Protection System and Automatic Reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

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

Automatic Reclosing –

- Reclosing relay
- Control circuitry associated with the reclosing relay through the close coil(s) of the circuit breakers or similar device but excluding breaker internal controls such as anti-pump and various interlock circuits.

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

A. Introduction

1. **Title:** Protection System and Automatic Reclosing Maintenance
2. **Number:** PRC-005-~~23~~
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that ~~these Protection Systemsthey~~ are kept in working order.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Transmission Owner
 - 4.1.2 Generator Owner
 - 4.1.3 Distribution Provider
 - 4.2. **Facilities:**
 - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4 Protection Systems installed as a Special Protection System (SPS) for BES reliability.
 - 4.2.5 Protection Systems for 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 for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
 - 4.2.6 Automatic Reclosing¹
 - 4.2.6.1 Applied on BES Elements at generating plant substations where the total installed generating plant capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area.

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 generation in the Interconnection exceeding the largest unit within the Balancing Authority Area where the Automatic Reclosing is applied.

4.2.6.2 Applied on 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 Applied as an integral part of a SPS specified in Section 4.2.4.

Component Type - Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

B. Requirements

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

The PSMP shall:

- 1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2. Include the applicable monitored Component attributes applied to each Protection System Component Type and Automatic Reclosing Components consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 34 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing

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

Component Type—Any one of the five specific elements of the Protection System definition.

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

Components.

- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 34. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

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.

C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.
- For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)
- For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each ~~protection~~Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table ~~34~~. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

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

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.3. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

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

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p><u>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</u></p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, <u>Table 3</u>, and <u>Table 34</u> where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity<u>entity’s</u> PSMP failed to specify whether three<u>four</u> or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 3) Maintained a Segment with

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				less than 60 Components OR 4) Failed to: <ul style="list-style-type: none"> • Annually update the list of Components, <li style="text-align: center;">OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, <li style="text-align: center;">OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, <u>Table 3</u> , and <u>Table 34</u> .	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, <u>Table 3</u> , and <u>Table 34</u> .	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, <u>Table 3</u> , and <u>Table 34</u> .	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, <u>Table 3</u> , and <u>Table 34</u> .
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System

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

E. Regional Variances

None

F. Supplemental Reference Document

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

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 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

Standard PRC-005-~~2~~-3 — Protection System and Automatic Reclosing Maintenance

1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees <u>Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0</u>	Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0
<u>3</u>	<u>TBD</u>	<u>Revision to include Automatic Reclosing into existing Version</u>	<u>Inclusion of Automatic Reclosing only</u>

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

² For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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.

<p style="text-align: center;">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)</p>		
<p style="text-align: center;">Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • 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
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).		

<p align="center">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)</p>		
<p align="center">Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

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

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS.	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring

In Tables 1-1 through 1-5, [Table 3](#), and [Table 3-4](#) 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
<p>Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Table 3-4 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.</p> <p>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.</p>	<p>12 Calendar Years</p>	<p>Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.</p>
<p>Alarm Path with monitoring:</p> <p>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.</p>	<p>No periodic maintenance specified</p>	<p>None.</p>

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: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2). 	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

<u>Table 4</u> Maintenance Activities and Intervals for Automatic Reclosing Components		
<u>Component Attributes</u>	<u>Maximum Maintenance Interval</u>	<u>Maintenance Activities</u>
<u>Any unmonitored reclosing relay not having all the monitoring attributes of a category below.</u>	<u>6 Calendar Years</u>	<u>Verify that settings are as specified</u> <u>For non-microprocessor relays:</u> <ul style="list-style-type: none"> • <u>Test and, if necessary calibrate</u> <u>For microprocessor relays:</u> <ul style="list-style-type: none"> • <u>Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</u>
<u>Monitored microprocessor reclosing relay with the following:</u> <ul style="list-style-type: none"> • <u>Internal self diagnosis and alarming (See Table 2).</u> • <u>Alarming for power supply failure (See Table 2).</u> 	<u>12 Calendar Years</u>	<u>Verify:</u> <ul style="list-style-type: none"> • <u>Settings are as specified.</u> • <u>Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</u>
<u>Unmonitored Control circuitry associated with Automatic Reclosing including the close coil.</u>	<u>12 Calendar Years</u>	<u>Verify the Automatic Reclosing control path including the close coil.</u>
<u>Control circuitry associated with Automatic Reclosing including the close coil whose integrity is monitored and alarmed (See Table 2).</u>	<u>No periodic maintenance specified</u>	<u>None.</u>

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

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

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

1. Develop a list with a description of Components included in each designated Segment ~~of the Protection System Component population~~, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Table 34 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – ~~Protection Systems or components~~ Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.

Countable Event – A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

Countable Event – ~~A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.~~

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

1. At least annually, update the list of ~~Protection System~~ Components and Segments and/or description if any changes occur within the Segment.

2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a ~~Protection System~~ Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Unofficial Comment Form

Project 2007-17.2 Protection System Maintenance – Phase 2 (Reclosing Relays) SAR for PRC-005-3

Please **DO NOT** use this form for submitting comments. Please use the [electronic form](#) to submit comments on the Standard Authorization Request (SAR). The electronic comment form must be completed by **8 p.m. ET, May 6, 2013**.

If you have questions please contact Al McMeekin at Al.McMeekin@nerc.net or by telephone at 803-530-1963.

[2007-17.2 Project Page](#)

Background Information

This posting is soliciting informal comment.

In response to Order No. 758, the Protection System Maintenance and Testing Standard Drafting Team drafted a Standard Authorization Request (SAR) to modify PRC-005 to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System. On May 10, 2012, the NERC Standards Committee (SC) accepted the SAR and authorized that it be posted for information only along with the 3rd draft of PRC-005-2. The NERC SC noted that PRC-005-2 was in the final stages of the development process, having passed a successive ballot with 79 percent approval on June 27, 2012 and was scheduled to be presented for approval at the November 2012 NERC Board of Trustees meeting. Consequently, in recognition of the consensus achieved, the NERC SC determined that the drafting team should complete the development of PRC-005-2 and immediately thereafter begin work on PRC-005-3 which would reflect the necessary revisions to address reclosing relays.

The scope of this project includes:

- The Applicability section of the Standard must be modified to describe explicitly those devices that entities are to maintain in accordance with the revised standard.
- The Tables of minimum maintenance activities and maximum maintenance intervals will require modification to include appropriate intervals and activities.
- The informative Supplementary Reference Document (provided as a technical reference for PRC-005-2) should be modified to provide the rationale for the maintenance activities and intervals within the modified standard, as well as to provide application guidance to industry.

Questions

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

1. Do you agree that the scope of this SAR addresses the regulatory directive associated with FERC Order No. 758? If not, please explain.

Yes

No

Comments:

2. Are you aware of any regional variances that will be needed as a result of this project? If yes, please identify the regional variance.

Yes

No

Comments:

3. Are you aware of any business practice that will be needed or that will need to be modified as a result of this project? If yes, please identify the business practice.

Yes

No

Comments:

4. If you have any other comments on this SAR that you haven't already mentioned, please provide them here:

Comments:

Unofficial Comment Form

1st Draft of PRC-005-3: Protection System and Automatic Reclosing Maintenance (Project 2007-17.2)

Please **DO NOT** use this form for submitting comments. Please use the [electronic form](#) to submit comments on the 1st draft of the standard PRC-005-3 for Protection System and Automatic Reclosing Maintenance. The electronic comment form must be completed by 8 p.m. ET May 6, 2013.

If you have questions please contact Al McMeekin at al.mcmeekin@nerc.net or by telephone at 803-530-1963.

[2007-17.2 Project Page](#)

Background Information

On February 3, 2012, the Federal Energy Regulatory Commission (FERC or Commission) issued Order No. 758 approving an interpretation of NERC Reliability Standard PRC-005-1, Transmission and Generation Protection System Maintenance and Testing. In addition to approving the interpretation, the Commission directed that concerns identified in the preceding Notice of Proposed Rulemaking (NOPR) be addressed within the reinitiated PRC-005 revisions. The concerns raised in the NOPR pertain to automatic reclosing (autoreclosing) relays that are either “used in coordination with a Protection System to achieve or meet system performance requirements established in other Commission-approved Reliability Standards, or can exacerbate fault conditions when not properly maintained and coordinated,” in which case “excluding the maintenance and testing of these reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the Bulk-Power System.” To address these concerns, the Commission concludes that “specific requirements or selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System.”

In response to Order No. 758, the Protection System Maintenance and Testing Standard Drafting Team (SDT) drafted a Standard Authorization Request (SAR) to modify PRC-005 to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System. On May 10, 2012, the NERC Standards Committee (SC) accepted the SAR and authorized that it be posted for information only along with the 3rd draft of PRC-005-2. The NERC SC noted that PRC-005-2 was in the final stages of the development process, having passed a successive ballot with 79 percent approval on June 27, 2012 and was scheduled to be presented for approval at the November 2012 NERC Board of Trustees meeting. Consequently, in recognition of the consensus achieved, the NERC SC determined that the drafting team should complete the development of PRC-005-2 and immediately thereafter begin work on PRC-005-3 which would reflect the necessary revisions to address reclosing relays.

The SDT also requested the NERC Planning Committee (PC) provide the technical input necessary to develop the appropriate revisions to PRC-005. The NERC PC instructed the NERC System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) to jointly perform a technical study to determine which reclosing relays should be addressed within PRC-005 and provide advice regarding the appropriate maintenance intervals and activities for those relays. The final report was approved by the NERC PC on November 14, 2012 and provided to the SDT for guidance in developing PRC-005-3.

In Order No. 758, the Commission also directed NERC to file, by July 30, 2012, either a completed project, or an informational filing providing “a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.” On July 30, 2012, NERC submitted an informational filing in compliance with Order No. 758 with a proposed schedule for addressing reclosing relays. The project number and name is as follows: Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)

On January 17, 2013, the NERC SC authorized the draft SAR be posted for formal industry comment concurrent with project development.

The PSMTSDT is presenting Draft 1 of PRC-005-3 for a 30-day formal comment period beginning April 5, 2013 and ending May 6, 2013.

Questions

You do not have to answer any questions. Enter All Comments in Simple Text Format. Bullets, numbers, and special formatting will not be retained. Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

NOTE: The Standards Authorization Request specifically limits this project to modifying PRC-005-2 to address the addition of reclosing relays which can affect the reliability of the BES, and specifically precludes general improvements to PRC-005-2.

1. The drafting team modified PRC-005-2 and its associated Supplementary Reference and FAQ document to address Automatic Reclosing as directed in FERC Order No. 758. Do you agree with these changes? If not, please provide specific suggestions for improvement.

Yes

No

Comments:

2. The drafting team developed an Implementation Plan for PRC-005-3 based on the Implementation Plan for PRC-005-2 to address the addition of Automatic Reclosing. Do you agree with the implementation plan regarding Automatic Reclosing? If not, please provide specific suggestions for improvement.

Yes

No

Comments:

Implementation Plan

Protection System and Automatic Reclosing Maintenance

PRC-005-3

Standards Involved

Approval:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Retirements:

- PRC-005-2 – Protection System Maintenance
- PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 – Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program
- PRC-011-0 – Undervoltage Load Shedding System Maintenance and Testing
- PRC-017-0 – Special Protection System Maintenance and Testing

Prerequisite Approvals:

N/A

Background:

Reliability Standard PRC-005-2 with its associated Implementation Plan was approved by the NERC Board of Trustees in November 2012 and has been filed with the applicable regulatory authorities for approval. The Implementation Plan for PRC-005-3 addresses both Protection Systems as outlined in PRC-005-2 and Automatic Reclosing components. PRC-005-3 establishes minimum maintenance activities for Automatic Reclosing Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-3 requires entities to revise the Protection System Maintenance Program by now including Automatic Reclosing Components. The implementation plan established under PRC-005-2 remains unchanged except for the addition of Automatic Reclosing Components required under PRC-005-3.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry-forward requirements from PRC-005-2, establish minimum maintenance activities for Protection System and Automatic Reclosing Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.

2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.
3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth in this document carries forward the implementation schedules contained in PRC-005-2 and includes changes needed to address the addition of Automatic Reclosing Components in PRC-005-3. According to the combined implementation plan in this document, entities must develop their revised Protection System Maintenance Program within twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees adoption of PRC-005-2. This anticipates that it will take approximately twelve (12) months to achieve regulatory approvals following the November 2012 adoption of PRC-005-2 by the NERC Board of Trustees.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standard PRC-005-3, in accordance with this implementation plan.

While entities are transitioning to the requirements of PRC-005-2, or the combined successor standard PRC-005-3, each entity must be prepared to identify:

- All of its applicable Protection System and Automatic Reclosing Components.
- Whether each component has last been maintained according to PRC-005-2 (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof.

For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active throughout the phased implementation period of PRC-005-3 and shall be applicable to an entity's Protection System Component maintenance activities not yet transitioned to PRC-005-3. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2.

The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees adoption.

Implementation Plan for Definition:

Protection System Maintenance Program – Entities shall use this definition when implementing any portions of R1, R2 R3, R4 and R5 which use this defined term.

Implementation Plan for Requirements R1, R2 and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30)

months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding

maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
6. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
7. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Implementation Plan

Project 2007-17 Protection Systems System and Automatic Reclosing Maintenance and Testing PRC-005-023

Standards Involved

Approval:

- PRC-005-23 – Protection System and Automatic Reclosing Maintenance ~~(PRC-005-2)~~

Retirements:

- PRC-005-2 – Protection System Maintenance
- PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing ~~(PRC-005-1b)~~
- PRC-008-0 – Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program ~~(PRC-008-0)~~
- PRC-011-0 – Undervoltage Load Shedding System Maintenance and Testing ~~(PRC-011-0)~~
- PRC-017-0 – Special Protection System Maintenance and Testing ~~(PRC-017-0)~~

Prerequisite Approvals:

~~Revised definition of “Protection System”~~
N/A

Background:

Reliability Standard PRC-005-2 with its associated Implementation Plan was approved by the NERC Board of Trustees in November 2012 and has been filed with the applicable regulatory authorities for approval. The Implementation Plan for PRC-005-3 addresses both Protection Systems as outlined in PRC-005-2 and Automatic Reclosing components. PRC-005-3 establishes minimum maintenance activities for Automatic Reclosing Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-3 requires entities to revise the Protection System Maintenance Program by now including Automatic Reclosing Components. The implementation plan established under PRC-005-2 remains unchanged except for the addition of Automatic Reclosing Components required under PRC-005-3.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry-forward requirements from PRC-005-2, establish minimum maintenance activities for Protection System ~~component types and~~ Automatic Reclosing Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.
2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.
3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.

4. The Implementation Schedule set forth in this document ~~requires that~~carries forward the implementation schedules contained in PRC-005-2 and includes changes needed to address the addition of Automatic Reclosing Components in PRC-005-3. According to the combined implementation plan in this document, entities must develop their revised Protection System Maintenance Program within twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees adoption ~~of PRC-005-2~~. This anticipates that it will take approximately twelve (12) months to achieve regulatory approvals following the November 2012 adoption of PRC-005-2 by the NERC Board of Trustees.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2 ~~in accordance with this implementation plan. Each entity shall be responsible for maintaining each of their Protection System components according to their maintenance program already in place for the legacy standards (PRC 005 1b, PRC 008 0, PRC 011 0, and PRC 017 0) or according to their maintenance program for PRC 005 2, but not both. Once an entity has designated PRC 005 2 as its maintenance program for specific Protection System components, they cannot revert to the original program for those components., or the combined successor standard PRC-005-3, in accordance with this implementation plan.~~

While entities are transitioning to the requirements of PRC-005-2, or the combined successor standard PRC-005-3, each entity must be prepared to identify:

- All of its applicable Protection System ~~components~~and Automatic Reclosing Components.
- Whether each component has last been maintained according ~~to PRC~~to PRC-005-2 or under (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, ~~or~~ PRC-017-0, or a combination thereof.

For activities being added to an entity's program as part of PRC-005-~~2~~3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-~~2~~3.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0, ~~which are being replaced by PRC-005-2,~~ shall remain active throughout the phased implementation period of PRC-005-~~23~~ and shall be applicable to an entity's Protection System ~~component~~Component maintenance activities not yet transitioned to PRC-005-~~2-3~~. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2.

The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees adoption.

Implementation Plan for Definition:

Protection System Maintenance Program – Entities shall use this definition when implementing any portions of R1, R2 R3, R4 and R5 which use this defined term.

Implementation Plan for Requirements R1, R2 and R5:

Entities For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System ~~component~~Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
2. For Protection System ~~component~~Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
3. For Protection System ~~component~~Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:
 - The entity shall be at least 30% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the

- November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
4. For Protection System ~~component~~Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:
- The entity shall be at least 30% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees adoption ~~of PRC-005-2~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
5. For ~~Protection System component~~Automatic Reclosing Component maintenance activities with maximum allowable intervals of ~~twelve (12)~~six (6) calendar years, as established in ~~Tables 1-1 through 1-5, Table 2, and Table 3-4~~:

- ~~The entity shall be at least 30% compliant with PRC-005-2~~ The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- ~~The entity shall be at least 60% compliant with PRC-005-2~~ The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant ~~with PRC-005-2~~ on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC

Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

7. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Violation Risk Factor and Violation Severity Level Justifications

Project 2007-17.2 PRC-005-3

Protection System and Automatic Reclosing Maintenance

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-005-2 - Protection System Maintenance.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Maintenance and Testing Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria – VRFs

High Risk Requirement

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

Medium Risk Requirement

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

Lower Risk Requirement

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

FERC VRF Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the VRF Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

PRC-005-3 Protection System and Automatic Reclosing Maintenance is a revision of PRC-005-2 Protection System Maintenance with the stated purpose: To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

PRC-005-3 has five (5) requirements that address the inclusion of Automatic Reclosing. A Table of minimum maintenance activities and maximum maintenance intervals has been added to PRC-005-2 to address FERC's directives from Order 758. The revised standard requires that entities develop an appropriate Protection System Maintenance Program (PSMP), that they implement their PSMP, and that, in the event they are unable to restore Automatic Reclosing Components to proper working order while performing maintenance, they initiate the follow-up activities necessary to resolve those maintenance issues.

The requirements of PRC-005-3 map one-to-one with the requirements of PRC-005-2. The drafting team did not revise the VRFs for the requirements of PRC-005-3.

PRC-005-3 Requirements R1 and R2 are related to developing and documenting a Protection System Maintenance Program. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violations of these requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

PRC-005-3 Requirements R3 and R4 are related to implementation of the Protection System Maintenance Program. The SDT determined that the assignment of a VRF of High was consistent with the NERC criteria that that violation of these requirements could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are assigned a VRF of High.

PRC-005-3 Requirement R5 relates to the initiation of resolution of unresolved maintenance issues, which describe situations where an entity was unable to restore a Component to proper working order during the performance of the maintenance activity. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violation of this requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

NERC Criteria - VSLs

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
<p>Missing a minor element (or a small percentage) of the required performance</p> <p>The performance or product measured has significant value as it almost meets the full intent of the requirement.</p>	<p>Missing at least one significant element (or a moderate percentage) of the required performance.</p> <p>The performance or product measured still has significant value in meeting the intent of the requirement.</p>	<p>Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital Component.</p> <p>The performance or product has limited value in meeting the intent of the requirement.</p>	<p>Missing most or all of the significant elements (or a significant percentage) of the required performance.</p> <p>The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.</p>

FERC Order on VSLs

In its June 19, 2008 Order on VSLs, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

- Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

- Guideline 2a: A violation of a “binary” type requirement must be a “Severe” VSL.
- Guideline 2b: Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: VSL Assignment Should Be Consistent with the Corresponding Requirement

- VSLs should not expand on what is required in the requirement.

Guideline 4: VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

- . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF and VSL Justifications

VRF and VSL Justifications – PRC-005-3, R1	
Proposed VRF	Medium
NERC VRF Discussion	Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so only one VRF was assigned. The requirement utilizes Parts to identify the items to be included within a Protection System Maintenance Program. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-2 Requirement R1.

VRF and VSL Justifications – PRC-005-3, R1			
Proposed VRF	Medium		
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs:</p> <p>Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:</p> <p>This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.</p>		
Proposed VSL – PRC-005-3, R1			
Lower	Moderate	High	Severe
<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p>OR</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p>OR</p>	<p>The responsible entity failed to establish a PSMP.</p> <p>OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>

Proposed VSL – PRC-005-3, R1			
Lower	Moderate	High	Severe
The responsible entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1)		The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	

VRF and VSL Justifications – PRC-005-3, R1	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R1

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R2	
Proposed VRF	Medium
NERC VRF Discussion	Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-2 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for.

VRF and VSL Justifications – PRC-005-3, R2			
Proposed VRF	Medium		
	Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-3, R2			
Lower	Moderate	High	Severe
The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	N/A	The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP

Proposed VSL – PRC-005-3, R2			
Lower	Moderate	High	Severe
			<p>OR</p> <p>2) Failed to reduce countable events to no more than 4% within five years</p> <p>OR</p> <p>3) Maintained a Segment with less than 60 Components</p> <p>OR</p> <p>4) Failed to:</p> <ul style="list-style-type: none"> • Annually update the list of Components, <p>OR</p> <ul style="list-style-type: none"> • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, <p>OR</p> <ul style="list-style-type: none"> • Annually analyze the program activities and results for each Segment.

VRF and VSL Justifications – PRC-005-3, R2	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R2

Guideline 2b: VSL Assignments that Contain Ambiguous Language	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R3	
Proposed VRF	High
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-3, R3			
Lower	Moderate	High	Severe
For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4.

VRF and VSL Justifications – PRC-005-3, R3

<p>NERC VSL Guidelines</p>	<p>Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.</p>
<p>FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.</p>
<p>FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: N/A</p> <p>Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – PRC-005-3, R3

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R4	
Proposed VRF	High
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-3, R4			
Lower	Moderate	High	Severe
For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.

VRF and VSL Justifications – PRC-005-3, R4	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R4

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R5	
Proposed VRF	Medium
NERC VRF Discussion	Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only requirement within approved Standards, PRC-004-2a Requirements R1 and R2 contain a similar requirement and is assigned a HIGH VRF. However, these requirements contain several subparts, and the VRF must address the most egregious risk related to these subparts, and a comparison to these requirements may be irrelevant. PRC-022-1 Requirement R1.5 contains only a similar requirement, and is assigned a MEDIUM VRF. FAC-003-2 Requirement R5 contains only a similar requirement, and is assigned a MEDIUM VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system.

VRF and VSL Justifications – PRC-005-3, R5			
Proposed VRF	Medium		
	<p>However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.</p>		
Proposed VSL – PRC-005-3, R5			
Lower	Moderate	High	Severe
The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

VRF and VSL Justifications – PRC-005-3, R5	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirement in PRC-005-2 has not been implemented; consequently, there is no prior level of compliance.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R5

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2007-17-~~2~~ -PRC-005-~~23~~

Protection System and Automatic Reclosing Maintenance

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-005-2 ~~23~~ Protection System Maintenance.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Maintenance and Testing Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria ~~Violation Risk Factors~~ VRFs

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

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

FERC ~~Violation Risk Factor~~ VRF Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that ~~Violation Risk Factors~~ VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement ~~Violation Risk Factor~~ VRF assignments and the main Requirement ~~Violation Risk Factor~~ VRF assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of ~~Violation Risk Factors~~VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC’s Definition of the ~~Violation Risk Factor~~VRF Level

Guideline (4) was developed to evaluate whether the assignment of a particular ~~Violation Risk Factor~~VRF level conforms to NERC’s definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC’s VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC’s Reliability Standards and implies that these requirements should be assigned a “High” VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

~~PRC-005-3 Protection System and Automatic Reclosing Maintenance is a revision of PRC-005-2 Protection System Maintenance is a revision of PRC-005-1a Transmission and Generation Protection System Maintenance and Testing~~ with the stated purpose: To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems they are kept in working order. ~~PRC-008-0 Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program, PRC-011-0 Undervoltage Load Shedding System Maintenance and Testing and PRC-017-0 Special Protection System Maintenance and Testing are also being replaced by merging them into~~

~~PRC-005-2 in accordance with suggestions from FERC Order 693. PRC-005-2 also establishes maximum allowable maintenance intervals as directed by FERC in Order 693 in their discussion of the legacy standards PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0.~~

~~PRC-005-23~~ has five (5) requirements that ~~incorporate and enhance the intent of the requirements of PRC-005-1a, PRC-008-0, PRC-011-0, and PRC-017-0. Several Tables address the inclusion of Automatic Reclosing. A Table of minimum maintenance activities and maximum maintenance intervals are also included~~ has been added to ~~addresses~~ PRC-005-2 to address FERC’s directives from Order ~~693~~758. The revised standard requires that entities develop an appropriate Protection System Maintenance Program (PSMP), that they implement their PSMP, and that, in the event they are unable to restore ~~Protection System~~Automatic Reclosing Components to proper working order while performing maintenance, they initiate the follow-up activities necessary to resolve those maintenance issues.

The requirements of PRC-005-~~2 do not~~³ map, one-to-one, with the requirements of PRC-005-2. The drafting team did not revise the legacy standards, each of which combine various attributes addressed within the new standard; thus, a requirement-to-requirement comparison of VRFs is irrelevant. When developing VRFs for the requirements of PRC-005-2, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. Therefore, PRC-005-2 Requirements R3 and R4 are assigned a VRF of High, while Requirements R1, R2, and R5 are assigned VRFs of Medium³.

PRC-005-~~2~~³ Requirements R1 and R2 are related to developing and documenting a Protection System Maintenance Program. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violations of these requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

PRC-005-~~2~~³ Requirements R3 and R4 are related to implementation of the Protection System Maintenance Program. The SDT determined that the assignment of a VRF of High was consistent with the NERC criteria that that violation of these requirements could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are assigned a VRF of High.

PRC-005-~~2~~³ Requirement R5 relates to the initiation of resolution of unresolved maintenance issues, which describe situations where an entity was unable to restore a Component to proper working order during the performance of the maintenance activity. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violation of this requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

NERC Criteria - ~~Violation Severity Levels~~ VSLs

~~Violation Severity Levels~~ (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

~~Violation severity levels~~ VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
<p>Missing a minor element (or a small percentage) of the required performance</p> <p>The performance or product measured has significant value as it almost meets the full intent of the requirement.</p>	<p>Missing at least one significant element (or a moderate percentage) of the required performance.</p> <p>The performance or product measured still has significant value in meeting the intent of the requirement.</p>	<p>Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital Component.</p> <p>The performance or product has limited value in meeting the intent of the requirement.</p>	<p>Missing most or all of the significant elements (or a significant percentage) of the required performance.</p> <p>The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.</p>

FERC Order on ~~Violation Severity Levels~~ VSLs

In its June 19, 2008 Order on ~~Violation Severity Levels~~ VSLs, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: ~~Violation Severity Level~~ VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

- Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: ~~Violation Severity Level~~ VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

- Guideline 2a: A violation of a “binary” type requirement must be a “Severe” VSL.
- Guideline 2b: Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: ~~Violation Severity Level~~ VSL Assignment Should Be Consistent with the Corresponding Requirement

- VSLs should not expand on what is required in the requirement.

Guideline 4: ~~Violation Severity Level~~ VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

- . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF and VSL Justifications

VRF and VSL Justifications – PRC-005-23, R1	
Proposed VRF	Medium
NERC VRF Discussion	Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so only one VRF was assigned. The requirement utilizes Parts to identify the items to be included within a Protection System Maintenance Program. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-2 Requirement R1.

VRF and VSL Justifications – PRC-005-23, R1			
Proposed VRF	Medium		
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs:</p> <p>Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:</p> <p>This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.</p>		
Proposed VSL – PRC-005-23, R1			
Lower	Moderate	High	Severe
<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;"><u>OR</u></p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection Systems specify whether three Component Type consistent with the Types are being addressed by time-based or performance-based maintenance intervals specified in Tables, or a combination of both. (Part 1-1 through 1-).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity entity’s PSMP failed to specify whether threefour or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>

		<u>OR</u>	
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Proposed VSL – PRC-005- 23 , R1			
Lower	Moderate	High	Severe
<p style="color: red; font-weight: bold;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program (Part 1.1)</p>		<p style="color: red; font-weight: bold;"><u>5, Table 2, and Table 3</u>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p>	<p style="color: red; font-weight: bold;">addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>

VRF and VSL Justifications – PRC-005-23, R1	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 Violation Severity VSL Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-33, R1

<p>FERC VSL G3 Violation Severity LevelVSL Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.</p>
<p>FERC VSL G4 Violation Severity LevelVSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSL is based on a single violation and not cumulative violations.</p>

VRF and VSL Justifications – PRC-005-~~23~~, R2

Proposed VRF	Medium
NERC VRF Discussion	Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-2 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for-

VRF and VSL Justifications – PRC-005-23, R2			
Proposed VRF	Medium		
	Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-23, R2			
Lower	Moderate	High	Severe
<u>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</u>	N/A	<u>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</u>	<u>The responsible entity uses performance-based maintenance intervals in its PSMP but:</u> <u>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</u>

<u>Proposed VSL – PRC-005-3, R2</u>			
Lower	Moderate	High	Severe
<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p>N/A</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p><u>OR</u></p> <p>2) _____ The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <p><u>1) Failed to establish the technical justification described reduce countable events to no more than 4% within Requirement R2 for five years</u></p> <p><u>OR</u></p> <p><u>3) Maintained a Segment with less than 60 Components</u></p> <p><u>OR</u></p> <p><u>4) Failed to:</u></p> <ul style="list-style-type: none"> <u>• Annually update the list of Components,</u> <p><u>OR</u></p> <ul style="list-style-type: none"> <u>• Annually perform maintenance on the initial use greater of 5% of the performance-based PSMP Segment population or 3 Components,</u>

			<u>OR</u> <ul style="list-style-type: none"> • <u>Annually analyze the program activities and results for each Segment.</u>
<u>VRF and VSL Justifications – PRC-005-3, R2</u>			
<u>NERC VSL Guidelines</u>	<u>Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.</u>		
<u>FERC VSL G1</u> <u>VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</u>	<u>This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.</u>		
<u>FERC VSL G2</u> <u>VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties</u> <u>Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent</u>	<u>Guideline 2a:</u> <u>N/A</u> <u>Guideline 2b:</u> <u>The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.</u>		

Proposed VSL – PRC-005-2, R2			
Lower	Moderate	High	Severe
			<p>OR</p> <p>2) Failed to reduce countable events to no more than 4% within five years</p> <p>OR</p> <p>3) Maintained a segment with less than 60 Components</p> <p>OR</p> <p>4) Failed to:</p> <ul style="list-style-type: none"> • Annually update the list of Components, <p>OR</p> <ul style="list-style-type: none"> • Annually perform maintenance on the greater of 5% of the segment population or 3 Components, <p>OR</p> <ul style="list-style-type: none"> • Annually analyze the program activities and results for each segment.

VRF and VSL Justifications— PRC-005-2, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-~~23~~, R2

<p>Guideline 2b: Violation Severity LevelVSL Assignments that Contain Ambiguous Language</p>	
<p>FERC VSL G3 Violation Severity LevelVSL Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.</p>
<p>FERC VSL G4 Violation Severity LevelVSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSL is based on a single violation and not cumulative violations.</p>

VRF and VSL Justifications – PRC-005-~~23~~, R3

Proposed VRF	High
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-23, R3			
Lower	Moderate	High	Severe
<p>For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 34.</p>	<p>For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 34.</p>	<p>For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 34.</p>	<p>For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 34.</p>

VRF and VSL Justifications – PRC-005-23, R3	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 Violation Severity Level VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-~~23~~, R3

<p>FERC VSL G3 Violation Severity LevelVSL Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.</p>
<p>FERC VSL G4 Violation Severity LevelVSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSL is based on a single violation and not cumulative violations.</p>

VRF and VSL Justifications – PRC-005-23, R4

Proposed VRF	High
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-23, R4			
Lower	Moderate	High	Severe
<p>For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.</p>	<p>For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.</p>	<p>For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.</p>	<p>For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.</p>

VRF and VSL Justifications – PRC-005-23, R4	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 Violation Severity Level VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-~~23~~, R4

<p>FERC VSL G3 Violation Severity LevelVSL Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.</p>
<p>FERC VSL G4 Violation Severity LevelVSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSL is based on a single violation and not cumulative violations.</p>

VRF and VSL Justifications – PRC-005- 23 , R5	
Proposed VRF	Medium
NERC VRF Discussion	Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only requirement within approved Standards, PRC-004-2a Requirements R1 and R2 contain a similar requirement and is assigned a HIGH VRF. However, these requirements contain several subparts, and the VRF must address the most egregious risk related to these subparts, and a comparison to these requirements may be irrelevant. PRC-022-1 Requirement R1.5 contains only a similar requirement, and is assigned a MEDIUM VRF. FAC-003-2 Requirement R5 contains only a similar requirement, and is assigned a MEDIUM VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system.

VRF and VSL Justifications – PRC-005-23, R5

Proposed VRF	Medium
	However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-23, R5

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

VRF and VSL Justifications – PRC-005-23, R5	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
<p>FERC VSL G1</p> <p>Violation Severity LevelVSL</p> <p>Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>This is a newThe Requirement <u>in PRC-005-2 has not been implemented</u>; consequently, there is no prior level of compliance.</p>
<p>FERC VSL G2</p> <p>Violation Severity LevelVSL</p> <p>Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties</p> <p>Guideline 2a: The Single Violation Severity LevelVSL Assignment Category for "Binary" Requirements Is Not Consistent</p> <p>Guideline 2b: Violation Severity LevelVSL Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: N/A</p> <p>Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – PRC-005-~~23~~, R5

<p>FERC VSL G3 Violation Severity Level<u>VSL</u> Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.</p>
<p>FERC VSL G4 Violation Severity Level<u>VSL</u> Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSL is based on a single violation and not cumulative violations.</p>

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Supplementary Reference and FAQ

PRC-005-3 Protection System Maintenance

April 2013

RELIABILITY | ACCOUNTABILITY



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1. Introduction and Summary

Note: This supplementary reference for PRC-005-3 is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-3 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the [NERC Glossary of Terms](#) used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- 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.

2.3 Applicability of New Protection System Maintenance Standards

The BES purpose is to transfer bulk power. The applicability language has been changed from the original PRC-005:

“...affecting the reliability of the Bulk Electric System (BES)...”

To the present language:

“...that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).”

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution

Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

NERC's approved definition of Bulk Electric System is:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.

The BES definition is presently undergoing the process of revision.

Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a [June 14, 2007 Informational Filing](#).

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your “non-BES circuit breaker” has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the “Facilities” section of “Applicability” track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Special Protection Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 94 (tripping or trip-free relay), as these devices are tripping relays that respond to the trip signal of the protective relay that processed the signals from the current and voltage-sensing devices.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.6.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

4.2.6.1 Applied on BES Elements at generating plant substations where the total installed generating plant capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area.

4.2.6.2 Applied on 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 Applied as an integral part of a SPS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 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 generation in the Interconnection exceeding the largest unit within the Balancing Authority Area where the Automatic Reclosing is applied.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when inadvertent reclosing near a generating station subjects the generation station to severe fault stresses. A technical report, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of "Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)"?

Reverse power relays are often installed to detect situations where the transmission source becomes deenergized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not 'installed for the purpose of detecting' these faults.

Is a Sudden Pressure Relay an auxiliary tripping relay?

No. IEEE C37.2-2008 assigns the Device No. 94 to auxiliary tripping relays. Sudden pressure relays are assigned Device No. 63. Sudden pressure relays are presently excluded from the standard because it does not utilize voltage and/or current measurements to determine anomalies. Devices that use anything other than electrical detection means are excluded. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

My mechanical device does not operate electrically and does not have calibration settings; what maintenance activities apply?

You must conduct a test(s) to verify the integrity of any trip circuit that is a part of a Protection System. This standard does not cover circuit breaker maintenance or transformer maintenance. The standard also does not presently cover testing of devices, such as sudden pressure relays (63), temperature relays (49), and other relays which respond to mechanical

parameters, rather than electrical parameters. There is an expectation that Fault pressure relays and other non-electrically initiated devices may become part of some maintenance standard. This standard presently covers trip paths. It might seem incongruous to test a trip path without a present requirement to test the device; and, thus, be arguably more work for nothing. But one simple test to verify the integrity of such a trip path could be (but is not limited to) a voltage presence test, as a dc voltage monitor might do if it were installed monitoring that same circuit.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: “A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.”

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: “A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.”

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-

based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft 86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System and Automatic Reclosing Components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing —

- Reclosing relay
- Control circuitry associated with the reclosing relay through the close coil(s) of the circuit breakers or similar device but excluding breaker internal controls such as anti-pump and various interlock circuits.

Unresolved Maintenance Issue — A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment — Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.

Component Type — Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Countable Event — A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action or a Misoperation attributed to hardware failure or calibration

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

4.1 Frequently Asked Questions:

Why does PRC-005-3 not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-3 requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the “Tables”), and the various components of the definition established for a “Protection System Maintenance Program,” PRC-005-3 establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by “restore” in the definition of maintenance.

The description of “restore” in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity “shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.” Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by “...demonstrate efforts to correct an Unresolved Maintenance Issue...”; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and

management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase “demonstrate efforts to correct” (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a “closed-end process”). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System and Automatic Reclosing Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System and Automatic Reclosing Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers’ recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.
- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term “Condition-Based-Maintenance” (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the “monitored-basis-time-intervals” existing within the standard, the

explanatory discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

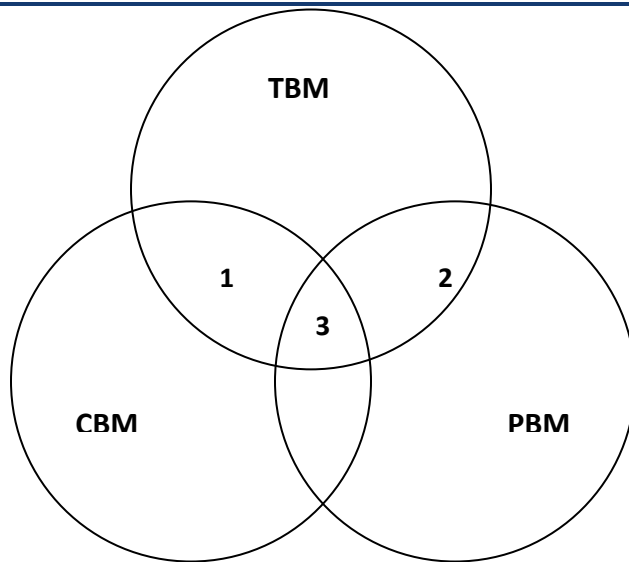
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to **ONLY** perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a “flow chart” of the standard.

We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

-
- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
 - Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

Excessive maintenance can actually decrease the reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.4) of the standard, is it necessary to

provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

“All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center.”

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

“Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability.”

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a combination of time-based and condition-based maintenance. The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-3. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-3.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a "One Calendar Year Interval," the next event would have to occur on or before December 31, 2010.

Please provide an example of "4 Calendar Months".

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number 5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May)

would still be due four months later therefore the activity is due again July. Basically every “four Calendar Months” means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions' section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

-
- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- 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 as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

-
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
 - Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Special Protection System. It may be a breaker, valve, distributed control system, or any variety of other devices.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, and Table 4 in the standard specify maximum allowable verification intervals for various generations of Protection Systems and Automatic Reclosing and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in [Figures 1](#) and [2](#) at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. [Figure 2](#) shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and SPS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-3:

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- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
 - Table 1-1 is for protective relays,
 - Table 1-2 is for the associated communications systems,
 - Table 1-3 is for current and voltage sensing devices,
 - Table 1-4 is for station dc supply and
 - Table 1-5 is for control circuits.
 - Table 2, is for alarms; this was broken out to simplify the other tables.
 - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
 - Table 4 is for Automatic Reclosing.
 - Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
 - This Maintenance activity is the minimum maintenance activity that must be documented.
 - If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
 - After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
 - If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
 - Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
 - An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows

maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-3. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-3, most notable of which is an entity using performance based maintenance methodology. If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc, are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.
2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.
3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or SPS (as opposed to a monitoring task) must be verified as a component in a Protection System.
4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-3 for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-3 is a more economical approach while addressing the reliability requirements of the BES.
5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform

properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).
7. “End-to-end test,” as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.
8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.
9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by “Verify that settings are as specified” maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states “...settings are as specified.”

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require “...that the relay settings be correct...” because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have “drifted” since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the “Verify that settings are as specified” maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about SPS interfaces between different entities or owners?

As in all of the Protection System requirements, SPS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Special Protection System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the SPS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for SPS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an SPS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an SPS scheme should that occur. Forced trip tests of circuit breakers (etc) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unnecessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval, then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays

-
- Neutral overcurrent relay
 - Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A

distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-3 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or to the previous scheduled (on-site) audit date, whichever is longer.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please use a specific example to demonstrate the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld. For example: “Company A” has a maintenance plan that requires its electromechanical protective relays be tested every three calendar years, with a maximum allowed grace period of an additional 18 months. This entity would be required to maintain its records of maintenance of its last two routine scheduled tests. Thus, its test records would have a latest routine test, as well as its previous routine test. The interval between tests is, therefore, provable to an auditor as being within “Company A’s” stated maximum time interval of 4.5 years.

The intent is not to require three test results proving two time intervals, but rather have two test results proving the last interval. The drafting team contends that this minimizes storage requirements, while still having minimum data available to demonstrate compliance with time intervals.

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-3, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-3 assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-3 requires performance of maintenance activities that are deemed necessary to detect and correct plausible age and service related degradation of components, such that a properly built and commission tested Protection System will continue to function as designed over its service life.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-3 would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the “Calendar Year” language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a “grace period” without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for “time-interval extensions” or “grace periods” to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. “Maximum time intervals” by their very term negates any “time-interval extension” or “grace periods.” To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was “...no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years...” The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table’s use of the term “Calendar” in the column for “Maximum Maintenance Interval.” The PSMT SDT deemed it necessary to include the term “Calendar” to

facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term “Calendar” to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity’s use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as *ISO 9001-2000, Quality Management Systems – Requirements*; or applicable parts of the NIST Baldrige National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is “the sampling distribution of the sample mean can be approximated by a normal probability distribution.” The Central Limit Theorem states: “In selecting simple random samples of size n from a population, the sampling distribution of the sample mean \bar{x} can be approximated by a normal probability distribution as the sample size becomes large.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

“... whenever we are using a large simple random sample (rule of thumb: $n \geq 30$), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

“If samples of size n , when $n \geq 30$, are drawn from any population with a mean μ and a standard deviation σ , the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation.” (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)

“The sample size is large (generally $n \geq 30$)... (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)

“... the normal is often used as an approximation to the t distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection.” (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a “Pass/Fail” format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z \sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1 - \pi) \left(\frac{z}{B} \right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.96 \text{ (This equates to a 95\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=59.0$.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.44 \text{ (85\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=31.8$.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design

errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing “86” lock-out relays (LOR). “Entity A” has two types of LOR’s type “X” and type “Y”; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type “X” failures, but human error led to tripping a BES Element 100 times; they find 100 type “Y” failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead “Entity A” to change time intervals. Type “X” LOR can be placed into extended time interval testing because of its low failure rate (zero failures) while Type “Y” would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment performance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, “reset the clock” on everything you’ve done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that “resetting the clock” should not be construed as interfering with an entity’s routine testing schedule because the “clock-reset” would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that “replaced relay” will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. $6/200 = 3\%$ failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. $6/100 = 6\%$ failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year ($1000/8$). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. $6/125 = 5\%$ failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year ($1000/7$). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. $6/143 = 4.2\%$ failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year ($1000/6$). After a year, they again find six

failures out of the 167 units tested. $6/167 = 3.6\%$ failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures “Control Circuitry” as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity’s specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device

that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year ($1000/12$). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures “voltage and current inputs to the protective relays” as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a “Relay Scheme.” Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT’s or specific PT’s. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 2000 “Relay Schemes,” all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT’s. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity’s relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their “Voltage and Current Sensing” population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays “that are designed to provide protection for the BES,” this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its

regularly scheduled cycle. (However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays “out-of-service”. What are our responsibilities when it comes to “out-of-service” devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-3 are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-3. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-3 to remove such component(s). Obviously, prudence would dictate that an “out-of-service” device is truly made inactive. There are no record requirements listed in PRC-005-3 for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-3 requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-3 requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

“R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.”

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state “...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues...” The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-3 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

These relays are defined as the devices that receive the input signal from the current and voltage sensing devices and are used to isolate a Faulted Element of the BES. Devices that sense thermal, vibration, seismic, pressure, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
 - There is no specific protective relay commissioning test or relay routine test mandated.
 - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the

protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and vars around the entire bus; this should add up to zero watts and zero vars, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "...verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ..." Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay

and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor- based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately “verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ...” while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "...designed to provide protection for the BES..." then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

While relays that do not respond to electrical quantities are presently excluded from this standard, their control circuits are included if the relay is installed to detect Faults on BES Elements. Thus, the control circuit of a BES transformer sudden pressure relay should be verified every 12 years, assuming its integrity is not monitored. While a sudden pressure relay control circuit is included within the scope of PRC-005-2, other alarming relay control circuits, (i.e., SF-6 low gas) are not included, even though they may trip the breaker being monitored.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes

that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-3 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-3 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-3 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.

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- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-3 applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have a non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- 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.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, “station batteries” are replaced with “station dc supply” to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-3 is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by “continuity” of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.

- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the

station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example “Conductance Readings” from one manufacturer’s test equipment do not correlate to “Impedance Readings” from a different manufacturer’s test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity

readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries).

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery

containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance “as designed” vs. battery performance “as manufactured.” The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer’s rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trendline against the established baseline. The type of probe and its location (post, connector, etc) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measurable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be “forming” after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an "adequate" ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one

minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-3 is there a maintenance activity to inspect the structural integrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.

Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the “Unintentional dc Grounds” requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a “check-off” of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to “all cells,” is it sufficient to have a documentation method that refers to “all cells,” or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-3 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980’s several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery’s current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The

inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "...depending on the degree of change a performance test, cell replacement or other corrective action may be necessary..." (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or

above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid 1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically

trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to “measure battery cell/unit internal ohmic values.” Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is “...verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline.” This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to “Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.”

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to ‘perform as manufactured.’ It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the “perform as manufactured six-month test” at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the “thermal runaway test” at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float

(charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to “verify station dc supply voltage” every “4 calendar months” (see table 1-4(a)), the owner can install a monitoring and alarming device “with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure” and “no periodic verification of station dc supply voltage is required” (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install “electrolyte level monitoring and alarming in every cell” and “unintentional dc ground monitoring and alarming” (see second and third rows of table 1-4(f)), the owner will have to “inspect electrolyte level and for unintentional grounds” every “4 calendar months” (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to “Protection System Control Circuitry”, rather than those portions of the table applicable to communications equipment.

What is meant by “Channel” and “Communications Systems” in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the “channel” as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting “performance criteria.” What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These

limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe “form-b” contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "...does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

None

15.9 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this Standard.

15.9.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics
- Maintenance records
- Logs (operator, substation, and other types of log)
- Inspection forms
- Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Check-off forms (paper or electronic)
- Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 (“Special Protection System Misoperation”). Can I also use it to show compliance for this Standard, PRC-005-3?

Maintaining evidence for operation of Special Protection Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-3.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

References

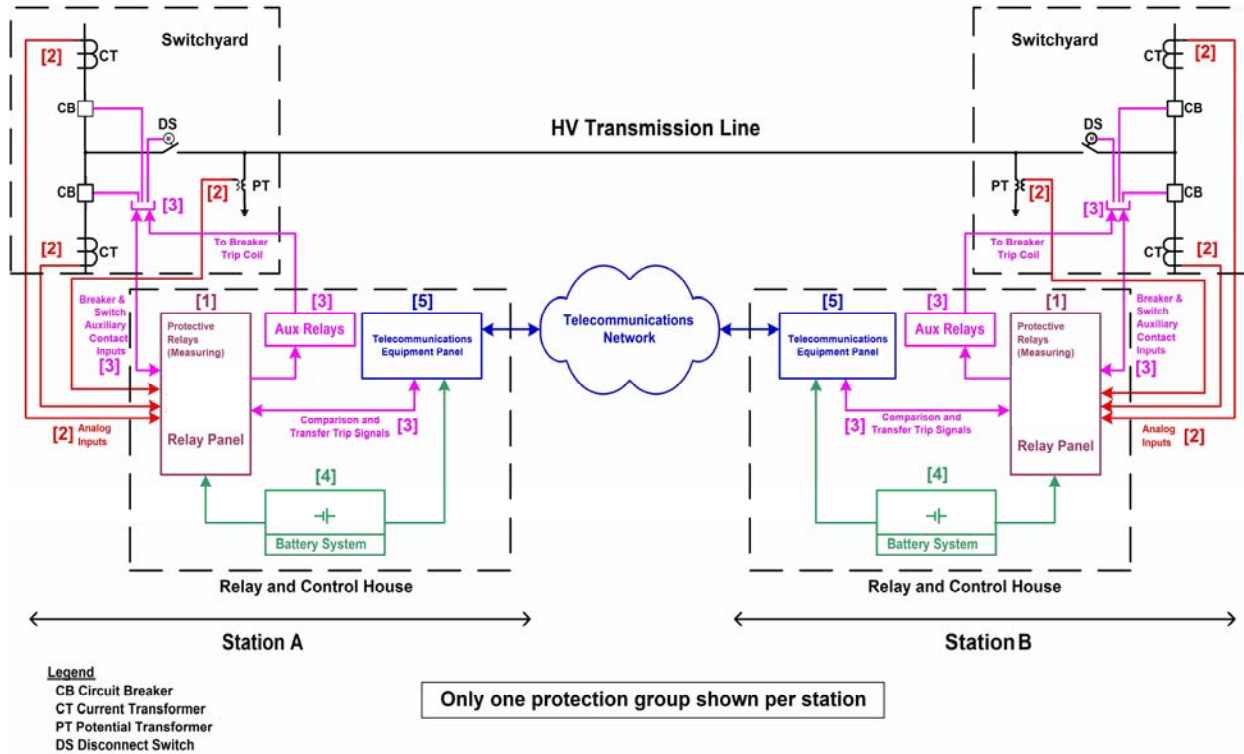
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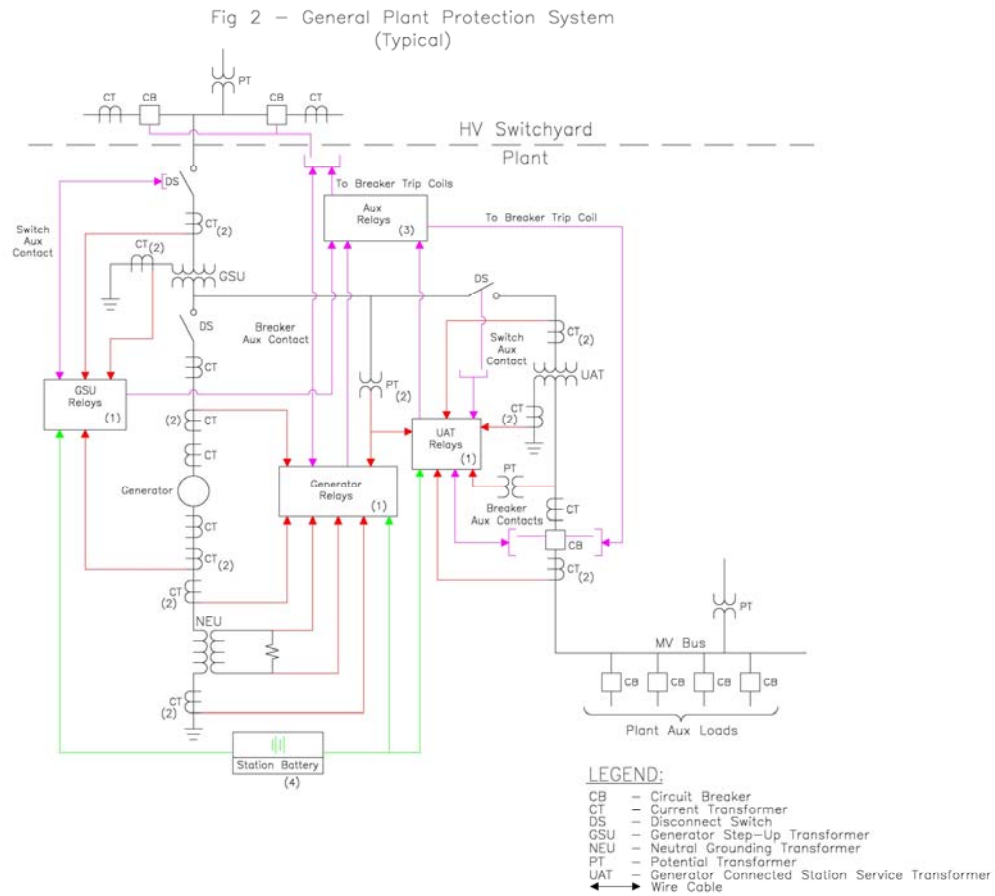
Figures

Figure 1: Typical Transmission System



For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 1 & 2 Legend – Components of Protection Systems

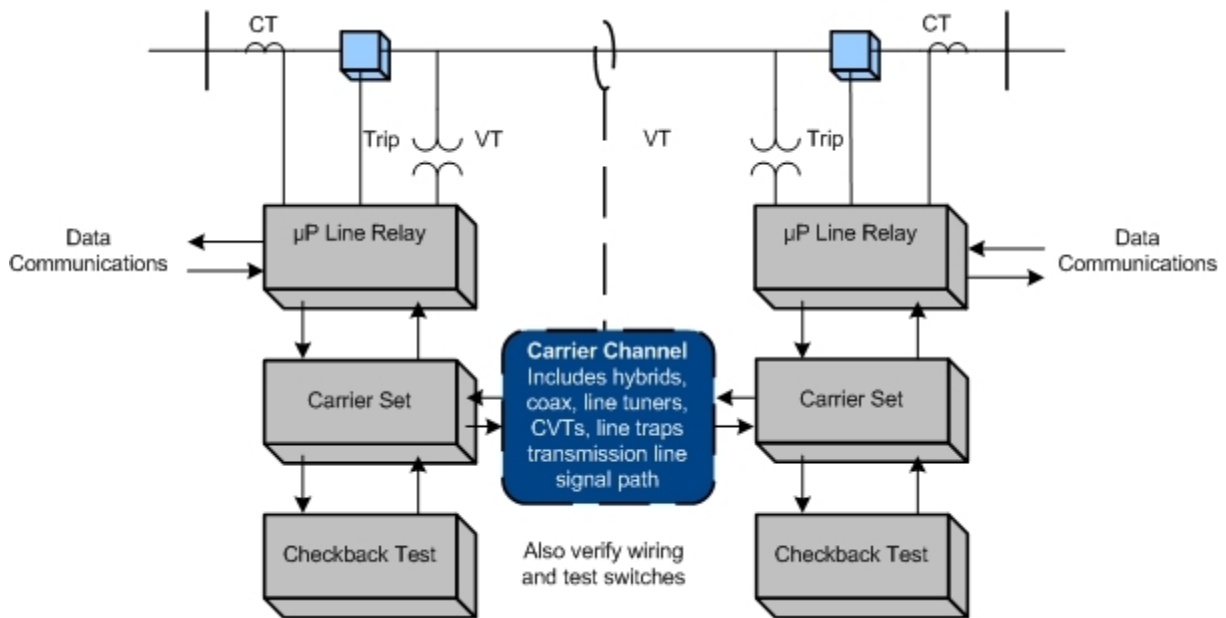
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

[Additional information can be found in References](#)

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line faults, and to avoid over-tripping for faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



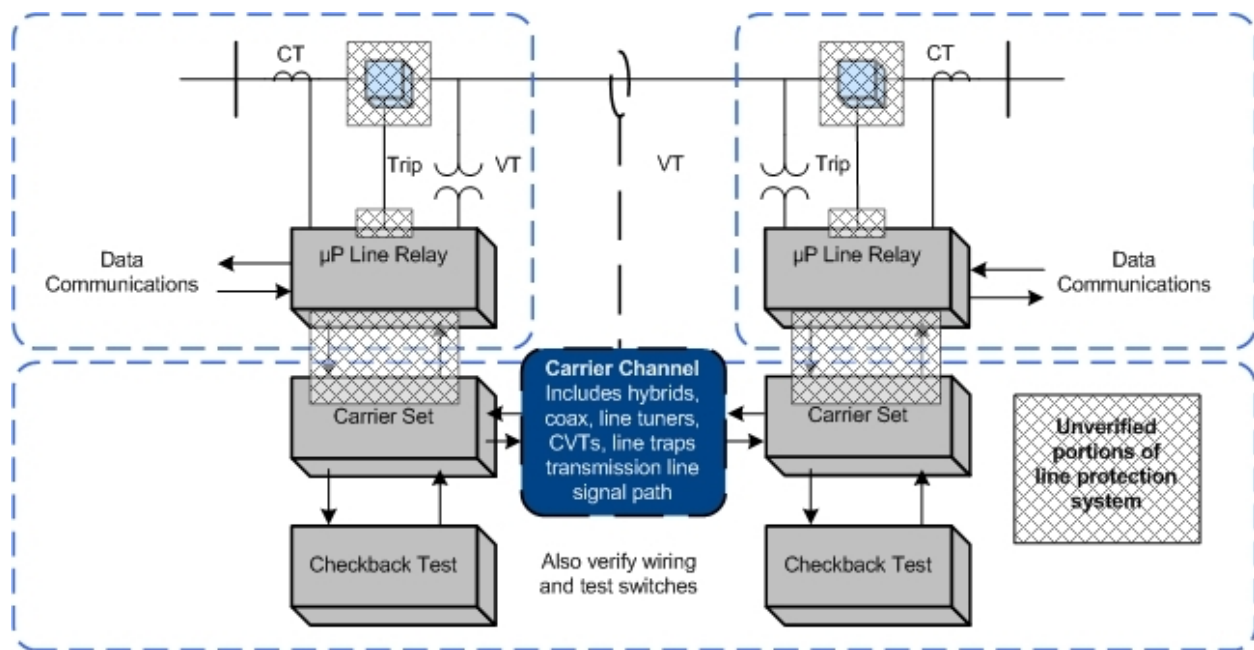
In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.
2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the

contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.

3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-3 does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

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Supplementary Reference and FAQ

PRC-005-~~2~~-3 Protection System Maintenance

~~October 2012~~ April 2013

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1. Introduction and Summary

Note: This supplementary reference for PRC-005-~~2~~3 is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-~~2~~3 will replace ~~and PRC-005-~~3~~2 which~~ combineds and replaceds PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-~~1~~3 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the [NERC Glossary of Terms](#) used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- 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.

2.3 Applicability of New Protection System Maintenance Standards

The BES purpose is to transfer bulk power. The applicability language has been changed from the original PRC-005:

“...affecting the reliability of the Bulk Electric System (BES)...”

To the present language:

“...that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).”

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution

Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-~~2-3~~ would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

~~As this standard PRC-005-2 is intended to replace~~ the existing PRC-005, PRC-008, PRC-011 and PRC-017, ~~those standards are used in the construction of this revision of PRC-005-1~~. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since ~~this standard PRC-005-2 will now replace~~ PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 ~~will is now be~~ applicable under ~~this revision of PRC-005-1~~ PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

NERC's approved definition of Bulk Electric System is:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.

The BES definition is presently undergoing the process of revision.

Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a [June 14, 2007 Informational Filing](#).

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-~~2-3~~ would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your “non-BES circuit breaker” has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the “Facilities” section of “Applicability” track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team ~~has~~ combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1**b** for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Special Protection Systems is addressed in 4.2.4;
- Applicability of PRC-005-1**b** for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 94 (tripping or trip-free relay), as these devices are tripping relays that respond to the trip signal of the protective relay that processed the signals from the current and voltage-sensing devices.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.6.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

~~No. This standard covers protective relays that use electrical quantity measurements to determine anomalies and to trip a portion of the BES. Reclosers, reclosing relays, closing circuits and auto restoration schemes are used to cause devices to close, as opposed to electrical measurement relays and their associated circuits that cause circuit interruption from the BES; such closing devices and schemes are more appropriately covered under other NERC standards. There is one notable exception: Since PRC-017 will be superseded by PRC-005-2, then if a Special Protection System (previously covered by PRC-017) incorporates automatic closing of breakers, then the SPS-related closing devices must be tested accordingly.~~
Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

4.2.6.1 Applied on BES Elements at generating plant substations where the total installed generating plant capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area.

4.2.6.2 Applied on 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 Applied as an integral part of a SPS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 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 generation in the Interconnection exceeding the largest unit within the Balancing Authority Area where the Automatic Reclosing is applied.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when inadvertent reclosing near a generating station subjects the generation station to severe fault stresses. A technical report, “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of “Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)”?

Reverse power relays are often installed to detect situations where the transmission source becomes deenergized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not ‘installed for the purpose of detecting’ these faults.

Is a Sudden Pressure Relay an auxiliary tripping relay?

No. IEEE C37.2-2008 assigns the Device No.# 94 to auxiliary tripping relays. Sudden pressure relays are assigned Device No.# 63. Sudden pressure relays are presently excluded from the standard because it does not utilize voltage and/or current measurements to determine anomalies. Devices that use anything other than electrical detection means are excluded. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-~~2-3~~ testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent

with the currently-approved PRC-005-~~4a1b~~, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

My mechanical device does not operate electrically and does not have calibration settings; what maintenance activities apply?

You must conduct a test(s) to verify the integrity of any trip circuit that is a part of a Protection System. This standard does not cover circuit breaker maintenance or transformer maintenance. The standard also does not presently cover testing of devices, such as sudden pressure relays (63), temperature relays (49), and other relays which respond to mechanical parameters, rather than electrical parameters. There is an expectation that Fault pressure relays and other non-electrically initiated devices may become part of some maintenance standard. This standard presently covers trip paths. It might seem incongruous to test a trip path without a present requirement to test the device; and, thus, be arguably more work for nothing. But one simple test to verify the integrity of such a trip path could be (but is not limited to) a voltage presence test, as a dc voltage monitor might do if it were installed monitoring that same circuit.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No.# 94, is described in IEEE Standard C37.2-2008 as: “A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.”

What is a lock-out relay?

A lock-out relay, IEEE Device No.# 86, is described in IEEE Standard C37.2 as: “A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.”

3. Protection System and Automatic Reclosings Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depends on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-

based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft 86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System ~~and Automatic Reclosing components~~ 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 — Detect visible signs of component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing –

- Reclosing relay
- Control circuitry associated with the reclosing relay through the close coil(s) of the circuit breakers or similar device but excluding breaker internal controls such as anti-pump and various interlock circuits.

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 – ~~Protection Systems or c~~Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.

Component Type – ~~Either a~~Any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, ~~and~~ Table 3, and Table 4 which requires corrective action or a Misoperation attributed to hardware failure or calibration

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

4.1 Frequently Asked Questions:

Why does PRC-005-~~2-3~~ not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-~~2-3~~ requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, ~~and~~ Table 3, and Table 4 (collectively the “Tables”), and the various components of the definition established for a “Protection System Maintenance Program,” PRC-005-~~2-3~~ establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by “restore” in the definition of maintenance.

The description of “restore” in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity “shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.” Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by “...demonstrate efforts to correct an Unresolved Maintenance Issue...”; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase “demonstrate efforts to correct” (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a “closed-end process”). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection Systems [and Automatic Reclosing Components](#) are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System [and Automatic Reclosing components-Components](#) can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers’ recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.
- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term “Condition-Based-Maintenance” (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the “monitored-basis-time-intervals” existing within the standard, the

explanatory discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

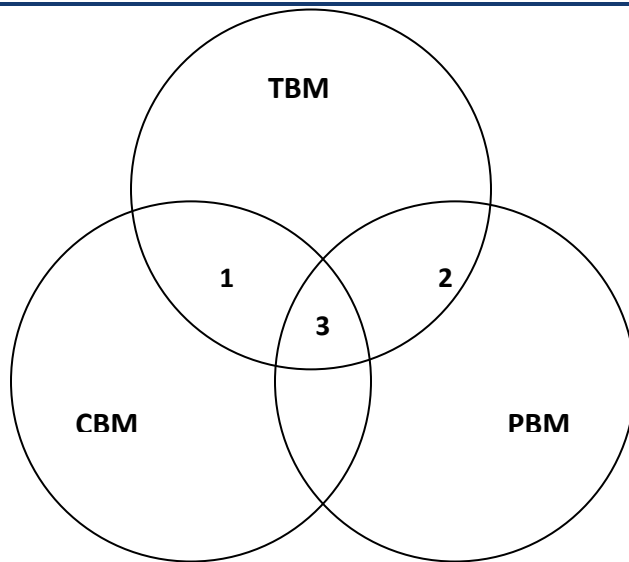
Microprocessor-based Protection System or Automatic Reclosing components Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

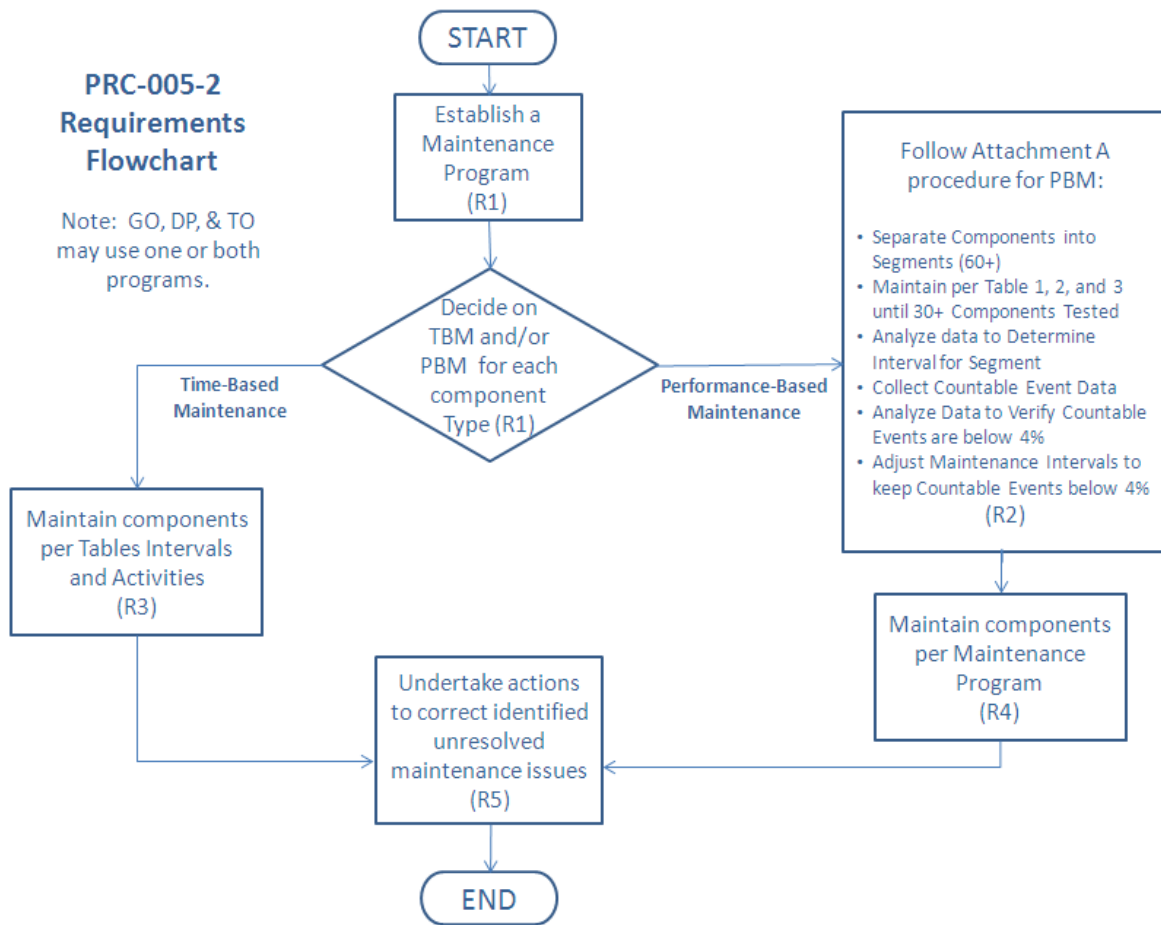
The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to **ONLY** perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a “flow chart” of the standard.

PRC-005-2 Requirements Flowchart

Note: GO, DP, & TO may use one or both programs.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System ~~maintenance-Maintenance program-Program~~ schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
- Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

Excessive maintenance can actually decrease the reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.4) of the standard, is it necessary to

provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

“All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center.”

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

“Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability.”

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a combination of time-based and condition-based maintenance. The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1**b** that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-~~23~~. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection Systems and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables 1-1 through 1-5 and Table 2 of PRC-005-~~23~~.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a "One Calendar Year Interval," the next event would have to occur on or before December 31, 2010.

Please provide an example of "4 Calendar Months".

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number 5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May)

would still be due four months later therefore the activity is due again July. Basically every “four Calendar Months” means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions' section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- 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 as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

-
- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
 - Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
- Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Special Protection System. It may be a breaker, valve, distributed control system, or any variety of other devices.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection Systems or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, ~~and~~ Table 3, and Table 4 in the standard specify maximum allowable verification intervals for various generations of Protection Systems and Automatic Reclosing and categories of equipment that comprise Protection Systems~~these systems~~. The right column indicates maintenance activities required for each category.

The types of components are illustrated in [Figures 1](#) and [2](#) at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. [Figure 2](#) shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and SPS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-~~23~~:

- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
 - Table 1-1 is for protective relays,
 - Table 1-2 is for the associated communications systems,
 - Table 1-3 is for current and voltage sensing devices,
 - Table 1-4 is for station dc supply and
 - Table 1-5 is for control circuits.
 - Table 2, is for alarms; this was broken out to simplify the other tables.
 - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
 - Table 4 is for Automatic Reclosing.
- Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
- This Maintenance activity is the minimum maintenance activity that must be documented.
- If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
- After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
- If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
- Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
- An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available ~~on-in~~ each of the ~~five~~-Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System ~~component~~Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component,

Table 4 shows maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-~~23~~. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-~~23~~, most notable of which is an entity using performance based maintenance methodology. If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

8.1.2 Additional Notes for Tables 1-1 through 1-5 ~~and~~ Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc, are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.
2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.
3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or SPS (as opposed to a monitoring task) must be verified as a component in a Protection System.
4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-~~2-3~~ for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-~~2-3~~ is a more economical approach while addressing the reliability requirements of the BES.
5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform

properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).
7. “End-to-end test,” as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.
8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.
9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by “Verify that settings are as specified” maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states “...settings are as specified.”

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require “...that the relay settings be correct...” because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have “drifted” since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the “Verify that settings are as specified” maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about SPS interfaces between different entities or owners?

As in all of the Protection System requirements, SPS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Special Protection System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the SPS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for SPS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an SPS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an SPS scheme should that occur. Forced trip tests of circuit breakers (etc) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unnecessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval, then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays

- Neutral overcurrent relay
- Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by “verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?”

Any input or output (of the relay) that “affects the tripping” of the breaker is included in the scope of I/O of the relay to be verified. By “affects the tripping,” one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be “picked up” or “turned on and off” and verified as changing state by the microprocessor of the relay. Each output should be “operated” or “closed and opened” from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to “jumper” the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A

distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-~~2~~3 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or to the previous scheduled (on-site) audit date, whichever is longer.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please use a specific example to demonstrate the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld. For example: “Company A” has a maintenance plan that requires its electromechanical protective relays be tested every three calendar years, with a maximum allowed grace period of an additional 18 months. This entity would be required to maintain its records of maintenance of its last two routine scheduled tests. Thus, its test records would have a latest routine test, as well as its previous routine test. The interval between tests is, therefore, provable to an auditor as being within “Company A’s” stated maximum time interval of 4.5 years.

The intent is not to require three test results proving two time intervals, but rather have two test results proving the last interval. The drafting team contends that this minimizes storage requirements, while still having minimum data available to demonstrate compliance with time intervals.

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-[2-3](#), verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-[2-3](#) assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-[2-3](#) requires performance of maintenance activities that are deemed necessary to detect and correct plausible age and service related degradation of components, such that a properly built and commission tested Protection System will continue to function as designed over its service life.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-[2-3](#) would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the “Calendar Year” language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a “grace period” without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for “time-interval extensions” or “grace periods” to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. “Maximum time intervals” by their very term negates any “time-interval extension” or “grace periods.” To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was “...no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years...” The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table’s use of the term “Calendar” in the column for “Maximum Maintenance Interval.” The PSMT SDT deemed it necessary to include the term “Calendar” to

facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term “Calendar” to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity’s use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as *ISO 9001-2000, Quality Management Systems – Requirements*; or applicable parts of the NIST Baldrige National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various ~~Protection System~~ Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of ~~Protection Systems or~~ Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other ~~e~~ Components ~~of a Protection System~~, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is “the sampling distribution of the sample mean can be approximated by a normal probability distribution.” The Central Limit Theorem states: “In selecting simple random samples of size n from a population, the sampling distribution of the sample mean \bar{x} can be approximated by a normal probability distribution as the sample size becomes large.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

“... whenever we are using a large simple random sample (rule of thumb: $n \geq 30$), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

“If samples of size n , when $n \geq 30$, are drawn from any population with a mean μ and a standard deviation σ , the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation.” (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)

“The sample size is large (generally $n \geq 30$)... (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)

“... the normal is often used as an approximation to the t distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection.” (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a “Pass/Fail” format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z \sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1 - \pi) \left(\frac{z}{B} \right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.96 \text{ (This equates to a 95\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=59.0$.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.44 \text{ (85\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=31.8$.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design

errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing “86” lock-out relays (LOR). “Entity A” has two types of LOR’s type “X” and type “Y”; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type “X” failures, but human error led to tripping a BES Element 100 times; they find 100 type “Y” failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead “Entity A” to change time intervals. Type “X” LOR can be placed into extended time interval testing because of its low failure rate (zero failures) while Type “Y” would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment performance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, “reset the clock” on everything you’ve done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that “resetting the clock” should not be construed as interfering with an entity’s routine testing schedule because the “clock-reset” would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that “replaced relay” will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. $6/200 = 3\%$ failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. $6/100 = 6\%$ failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year ($1000/8$). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. $6/125 = 5\%$ failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year ($1000/7$). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. $6/143 = 4.2\%$ failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year ($1000/6$). After a year, they again find six

failures out of the 167 units tested. $6/167 = 3.6\%$ failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures “Control Circuitry” as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment —~~Protection Systems or Components~~ of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity’s specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device

that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year ($1000/12$). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures “voltage and current inputs to the protective relays” as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a “Relay Scheme.” Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT’s or specific PT’s. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment – ~~Protection Systems or~~ **Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.**

Example:

Entity has 2000 “Relay Schemes,” all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT’s. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity’s relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their “Voltage and Current Sensing” population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested ($U = P/I$)	# of Failures Found (F)	Failure Rate ($=F/U$)	Decision to Change Interval Yes or No	Interval Chose
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2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays “that are designed to provide protection for the BES,” this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its

regularly scheduled cycle. (However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays “out-of-service”. What are our responsibilities when it comes to “out-of-service” devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-~~2-3~~ are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-~~2-3~~. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-~~2-3~~ to remove such component(s). Obviously, prudence would dictate that an “out-of-service” device is truly made inactive. There are no record requirements listed in PRC-005-~~2-3~~ for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-~~2-3~~ requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-~~2-3~~ requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

“R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.”

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state “...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues...” The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-~~2~~-3 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

These relays are defined as the devices that receive the input signal from the current and voltage sensing devices and are used to isolate a Faulted Element of the BES. Devices that sense thermal, vibration, seismic, pressure, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
 - There is no specific protective relay commissioning test or relay routine test mandated.
 - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the

protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and vars around the entire bus; this should add up to zero watts and zero vars, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "...verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ..." Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay

and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor-based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately “verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ...” while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "...designed to provide protection for the BES..." then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

While relays that do not respond to electrical quantities are presently excluded from this standard, their control circuits are included if the relay is installed to detect Faults on BES Elements. Thus, the control circuit of a BES transformer sudden pressure relay should be verified every 12 years, assuming its integrity is not monitored. While a sudden pressure relay control circuit is included within the scope of PRC-005-2, other alarming relay control circuits, (i.e., SF-6 low gas) are not included, even though they may trip the breaker being monitored.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-~~2-3~~ testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes

that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1**b**, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-~~2-3~~ are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-~~2-3~~ sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.


How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-~~2-3~~ includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-~~2-3~~ applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
-  The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.

- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-~~2-3~~ applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have an non-BES circuit breaker that is tripped via a Protection System to which PRC-005-~~2-3~~ applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or ~~auxiliary~~auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker “a” contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- 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.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, “station batteries” are replaced with “station dc supply” to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-~~2-3~~ is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging

technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by “continuity” of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these

harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.

- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example “Conductance Readings” from one manufacturer’s test equipment do not correlate to “Impedance Readings” from a different manufacturer’s test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity

readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries).

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery

containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance “as designed” vs. battery performance “as manufactured.” The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer’s rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trendline against the established baseline. The type of probe and its location (post, connector, etc) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measurable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be “forming” after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an "adequate" ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one

minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-2-3 is there a maintenance activity to inspect the structural integrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.

Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the “Unintentional dc Grounds” requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a “check-off” of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to “all cells,” is it sufficient to have a documentation method that refers to “all cells,” or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-2-3 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980’s several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery’s current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The

inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "...depending on the degree of change a performance test, cell replacement or other corrective action may be necessary..." (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or

above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid 1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically

trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to “measure battery cell/unit internal ohmic values.” Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is “...verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline.” This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to “Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.”

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to ‘perform as manufactured.’ It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the “perform as manufactured six-month test” at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the “thermal runaway test” at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float

(charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to “verify station dc supply voltage” every “4 calendar months” (see table 1-4(a)), the owner can install a monitoring and alarming device “with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure” and “no periodic verification of station dc supply voltage is required” (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install “electrolyte level monitoring and alarming in every cell” and “unintentional dc ground monitoring and alarming” (see second and third rows of table 1-4(f)), the owner will have to “inspect electrolyte level and for unintentional grounds” every “4 calendar months” (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to “Protection System Control Circuitry”, rather than those portions of the table applicable to communications equipment.

What is meant by “Channel” and “Communications Systems” in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the “channel” as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

-
- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting “performance criteria.” What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These

limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, [Table 3](#), and [Table 4](#). The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe “form-b” contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "...does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

None

15.8.9 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this Standard.

15.8.9.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics
- Maintenance records
- Logs (operator, substation, and other types of log)
- Inspection forms
- Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Check-off forms (paper or electronic)
- Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 (“Special Protection System Misoperation”). Can I also use it to show compliance for this Standard, PRC-005-~~23~~?

Maintaining evidence for operation of Special Protection Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-~~23~~.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

References

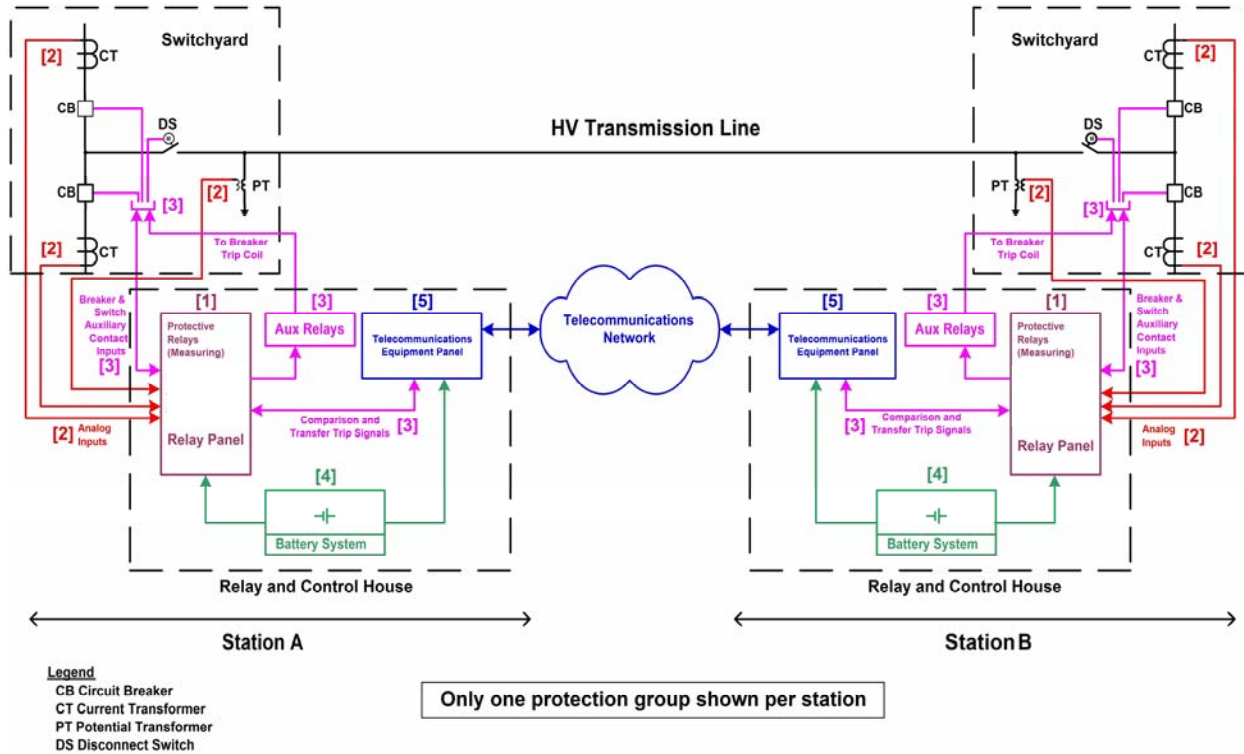
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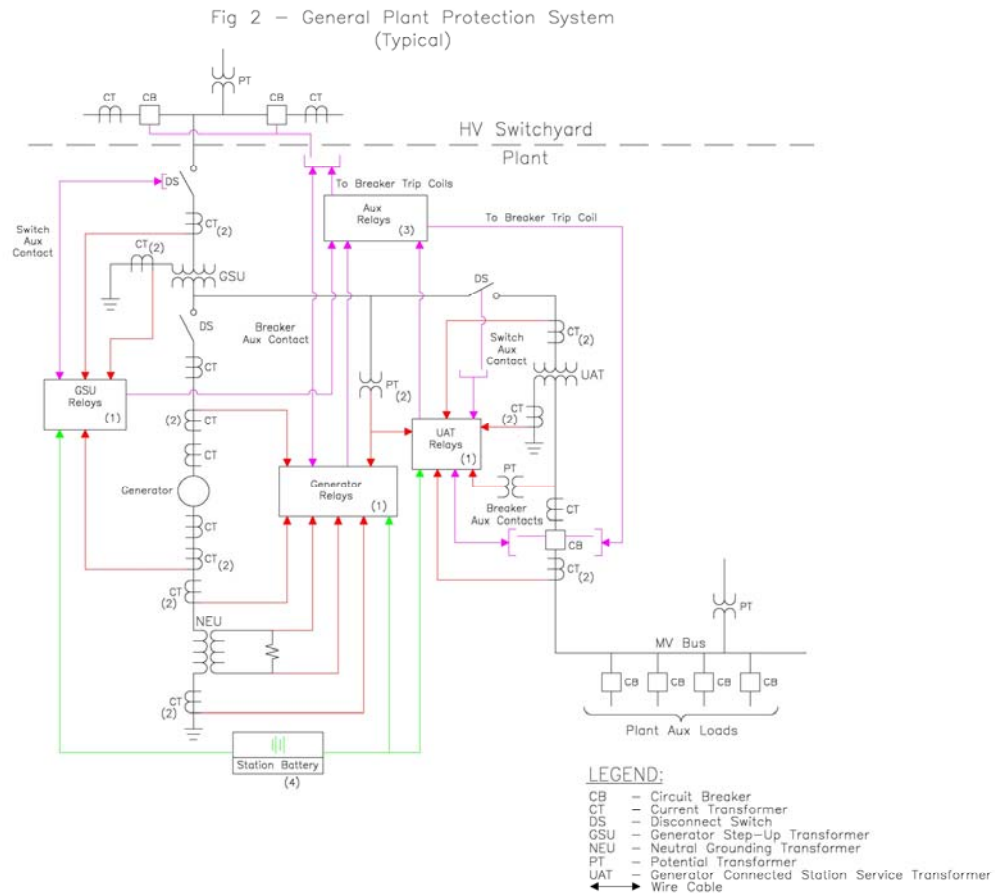
Figures

Figure 1: Typical Transmission System



For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 1 & 2 Legend – ~~components~~ Components of Protection Systems

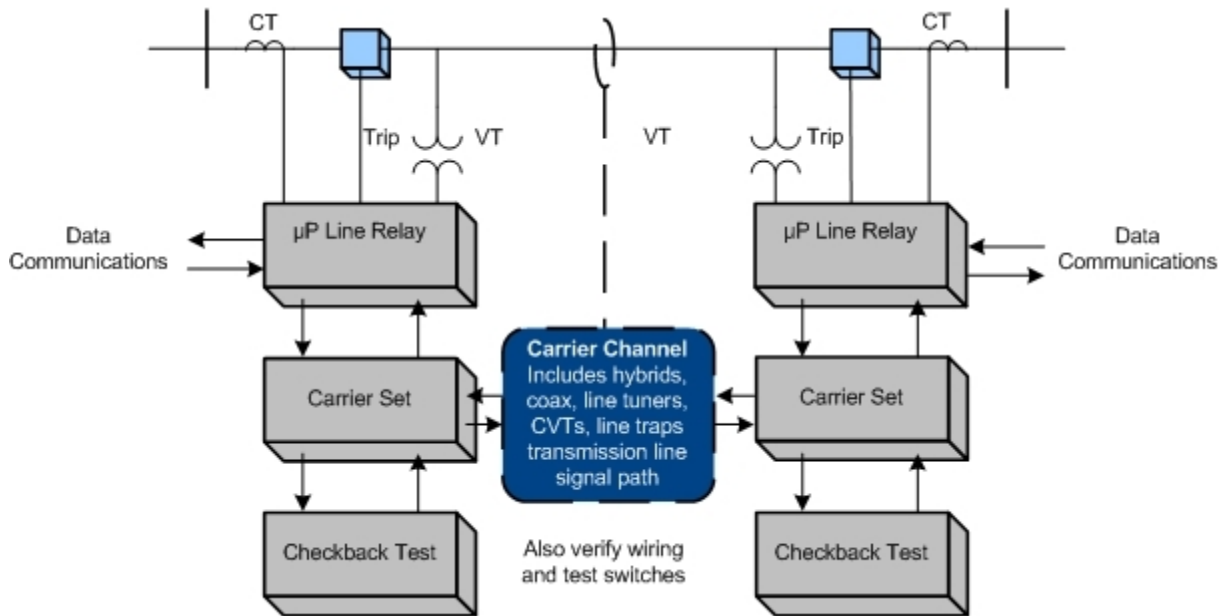
Number in Figure	component <u>Component</u> of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

[Additional information can be found in References](#)

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line faults, and to avoid over-tripping for faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



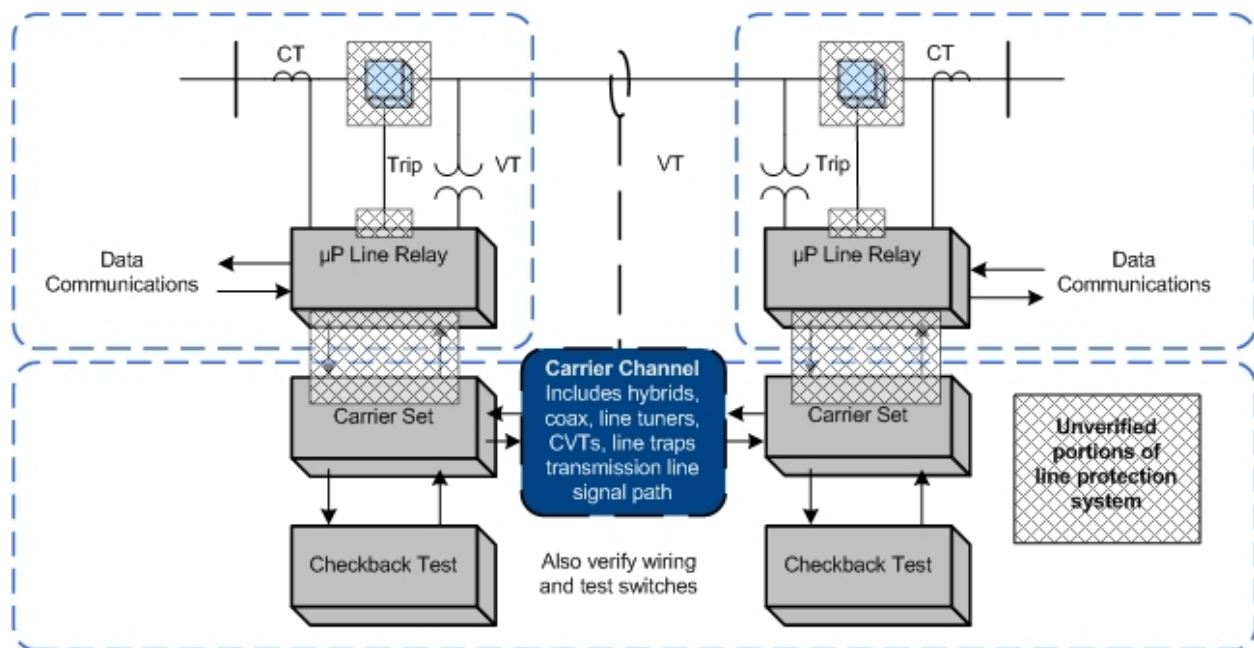
In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.
2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the

contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.

3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-[3](#) does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

Protection System Maintenance Standard Drafting Team

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Table of Issues and Directives

Project 2007-17.2 PRC-005-3

Protection System and Automatic Reclosing Maintenance

Table of Issues and Directives Associated with PRC-005-3

Source	Directive Language (including pg #)	Disposition	Section and/or Requirement(s)
FERC Order 758	27. We note that the original project to revise Reliability Standard PRC-005 failed a recirculation ballot in July of 2011. The project was subsequently reinitiated to continue the efforts to develop Reliability Standard PRC-005-2. Given that the project to draft proposed revisions to Reliability Standard PRC-005-1 continues in this reinitiated effort, and the importance of maintaining and testing reclosing relays, we direct NERC to include maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System, as discussed above, within these reinitiated efforts to revise Reliability Standard PRC-005.	Specific minimum activities and maximum allowable intervals are included in the draft standard within Table 4.	Applicability 4.2.6 Requirement R1, R3, Requirement R4, Table 4

138 FERC ¶ 61,094
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM10-5-000; Order No. 758]

Interpretation of Protection System Reliability Standard

(Issued February 3, 2012)

AGENCY: Federal Energy Regulatory Commission

ACTION: Final Rule

SUMMARY: On November 17, 2009, the North American Electric Reliability Corporation (NERC) submitted a petition (Petition) requesting approval of NERC's interpretation of Requirement R1 of Commission-approved Reliability Standard PRC-005-1 (Transmission and Generation Protection System Maintenance and Testing). On December 16, 2010, the Commission issued a Notice of Proposed Rulemaking (NOPR). In the NOPR, the Commission proposed to accept the NERC proposed interpretation of Requirement R1 of Reliability Standard PRC-005-1, and proposed to direct NERC to develop modifications to the PRC-005-1 Reliability Standard through its Reliability Standards development process to address gaps in the Protection System maintenance and testing standard that were highlighted by the proposed interpretation. As a result of the comments received in response to the NOPR, in this order the Commission adopts the NOPR proposal to accept NERC's proposed interpretation. In addition, as discussed below, the Commission accepts, in part, NERC's commitment to address the concerns in the Protection System maintenance and testing standard that were identified by the NOPR

within the Reliability Standards development process, and directs, in part, that the concerns identified by the NOPR with regard to reclosing relays be addressed within the reinitiated PRC-005 revisions.

EFFECTIVE DATE: This rule will become effective 30 days after publication in the FEDERAL REGISTER.

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SUPPLEMENTARY INFORMATION:

138 FERC ¶ 61,094
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Interpretation of Protection System Reliability Standard Docket No. RM10-5-000

ORDER NO. 758

FINAL RULE

(Issued February 3, 2012)

1. On November 17, 2009, NERC submitted the Petition requesting approval of NERC's interpretation of Requirement R1 of Commission-approved Reliability Standard PRC-005-1 (Transmission and Generation Protection System Maintenance and Testing). NERC developed the interpretation in response to a request for interpretation submitted to NERC by the Regional Entities Compliance Monitoring Processes Working Group (Working Group).¹ In a December 16, 2010 Notice of Proposed Rulemaking (NOPR),² the Commission proposed to accept the NERC proposed interpretation of Requirement R1 of Reliability Standard PRC-005-1, and proposed to direct NERC to develop modifications to the PRC-005-1 Reliability Standard through its Reliability Standards

¹ The Working Group is a subcommittee of the Regional Entity Management Group which consists of the executive management of the eight Regional Entities.

² *Interpretation of Protection System Reliability Standard*, Notice of Proposed Rule Making, 75 FR 81,152 (Dec. 27, 2010), FERC Stats. & Regs. ¶ 32,669 (2010).

development process to address gaps in the Protection System maintenance and testing standard highlighted by the proposed interpretation. As a result of the comments received in response to the NOPR, in this order the Commission adopts the NOPR proposal to accept NERC's proposed interpretation. In addition, the Commission accepts, in part, NERC's commitments to address the concerns in the Protection System maintenance and testing standard that were identified by the NOPR within the Reliability Standards development process, and directs, in part, that the concerns identified by the NOPR with regard to reclosing relays be addressed within the reinitiated PRC-005 revisions.

I. Background

2. Section 215 of the Federal Power Act (FPA) requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval.³ Specifically, the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.⁴

³ 16 U.S.C. 824 (2006).

⁴ *Id.* 824o(d)(2).

Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.⁵

3. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,⁶ and subsequently certified NERC.⁷ On April 4, 2006, NERC submitted to the Commission a petition seeking approval of 107 proposed Reliability Standards. On March 16, 2007, the Commission issued a Final Rule, Order No. 693,⁸ approving 83 of the 107 Reliability Standards, including Reliability Standard PRC-005-1. In addition, pursuant to section 215(d)(5) of the FPA,⁹ the Commission directed NERC to develop modifications to 56 of the 83 approved Reliability Standards, including PRC-005-0.¹⁰

⁵ *Id.* 824o(e)(3).

⁶ *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

⁷ *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

⁸ *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

⁹ 16 U.S.C. 824o(d)(5).

¹⁰ Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1475.

4. NERC's Rules of Procedure provide that a person that is "directly and materially affected" by Bulk-Power System reliability may request an interpretation of a Reliability Standard.¹¹ In response, the ERO will assemble a team with relevant expertise to address the requested interpretation and also form a ballot pool. NERC's Rules of Procedure provide that, within 45 days, the team will draft an interpretation of the Reliability Standard and submit it to the ballot pool. If approved by the ballot pool and subsequently by the NERC Board of Trustees (Board), the interpretation is appended to the Reliability Standard and filed with the applicable regulatory authorities for approval.

II. Reliability Standard PRC-005-1

5. The purpose of PRC-005-1 is to "ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested." In particular, Requirement R1, requires that:

R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:

R1.1. Maintenance and testing intervals and their basis.

¹¹ NERC Rules of Procedure, Appendix 3A, Reliability Standards Development Procedure, Version 6.1, at 26-27 (2007).

R1.2. Summary of maintenance and testing procedures.

6. NERC currently defines “Protection System” as follows: “Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.”¹²

III. NERC Proposed Interpretation

7. In the NERC Petition, NERC explains that it received a request from the Working Group for an interpretation of Reliability Standard PRC-005-1, Requirement R1, addressing five specific questions. Specifically, the Working Group questions and NERC proposed interpretations include:

Request 1: “Does R1 require a maintenance and testing program for the battery chargers for the ‘station batteries’ that are considered part of the Protection System?”

Response: “While battery chargers are vital for ensuring ‘station batteries’ are available to support Protection System functions, they are not identified within the definition of

¹² In Docket No. RD11-13-000, NERC has proposed to revise the definition of Protection System effective on the first day of the first calendar quarter twelve months from approval. The Commission is approving this revision in an order issued concurrently with this order. See *North American Electric Reliability Corp.*, 138 FERC ¶ 61,095 (2012).

‘Protection Systems.’ Therefore, PRC-005-1 does not currently require maintenance and testing of battery chargers.”¹³

Request 2: “Does R1 require a maintenance and testing program for auxiliary relays and sensing devices? If so, what types of auxiliary relays and sensing devices? (i.e., transformer sudden pressure relays).”

Response: “The existing definition of ‘Protection System’ does not include auxiliary relays; therefore, maintenance and testing of such devices is not explicitly required. Maintenance and testing of such devices is addressed to the degree that an entity’s maintenance and testing program for DC control circuits involves maintenance and testing of imbedded auxiliary relays. Maintenance and testing of devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included within Requirement R1.”

Request 3: “Does R1 require maintenance and testing of transmission line re-closing relays?”

Response: “No. ‘Protective Relays’ refer to devices that detect and take action for

¹³ The revised definition of Protection System accepted in Docket No. RD11-13-000 includes battery chargers as an element of the Protection System and, as a result of that change, battery chargers must be maintained and tested. Thus, the modified definition of Protection System approved in Docket No. RD11-13-000, when effective, shall supersede the interpretation of Requirement R1 of Reliability Standard PRC-005-1 approved in this order.

abnormal conditions. Automatic restoration of transmission lines is not a ‘protective’ function.”

Request 4: “Does R1 require a maintenance and testing program for the DC circuitry that is just the circuitry with relays and devices that control actions on breakers, etc., or does R1 require a program for the entire circuit from the battery charger to the relays to circuit breakers and all associated wiring?”

Response: “PRC-005-1 requires that entities 1) address DC control circuitry within their program, 2) have a basis for the way they address this item, and 3) execute the program. Specific additional requirements relative to the scope and/or methods are not established.”

Request 5: “For R1, what are examples of ‘associated communications systems’ that are part of ‘Protection Systems’ that require a maintenance and testing program?”

Response: “Associated communication systems” refer to communication systems used to convey essential Protection System tripping logic, sometimes referred to as pilot relaying or teleprotection. Examples include the following:

- communications equipment involved in power-line-carrier relaying;
- communications equipment involved in various types of permissive protection system applications;
- direct transfer-trip systems;
- digital communication systems”

8. In its Petition requesting that the Commission accept the proposed interpretation, NERC recognized that greater clarity to the requirement language in PRC-005-1a is necessary to provide a complete framework for maintenance and testing of equipment necessary to ensure the reliability of the Bulk Power System. In its Petition, NERC also stated that this activity is already underway in the scope of Project 2007-17 – Protection System Maintenance and Testing, coupled with the revised definition of Protection System.

IV. Commission NOPR

9. In the NOPR, the Commission proposed to accept the NERC proposed interpretation of Requirement R1 of Reliability Standard PRC-005-1. In addition, the Commission proposed to direct NERC to develop modifications to the PRC-005-1 Reliability Standard through its Reliability Standards development process to address gaps in the Protection System maintenance and testing standard that were highlighted by the proposed interpretation. The specific modifications are discussed below.

V. Comments

10. Comments on the Commission's proposed interpretation were received by the NERC, Edison Electric Institute (EEI), ISO/RTO Council (IRC), American Public Power Association (APPA), National Rural Electric Cooperative Association (NRECA), Transmission Access Policy Study Group (TAPS), Cities of Anaheim and Riverside,

California (Joint Cities), Northwest Commenters,¹⁴ International Transmission Company (ITC), PSEG Companies,¹⁵ and MidAmerican Energy Holdings Company (MidAmerican), Constellation/CENG,¹⁶ and Manitoba Hydro (Manitoba). In general, commenters support NERC's proposed interpretation, and oppose the further directives in the NOPR. Commenters also state that modifications to the Reliability Standards should be addressed within the NERC standards development process and that certain of the modifications are currently being addressed.

VI. Discussion

11. As a result of the comments received in response to the proposal, the Commission adopts the NOPR proposal to accept NERC's proposed interpretation. As discussed below,¹⁷ the Commission accepts, in part, NERC's commitments to address the concerns

¹⁴ Lincoln People's Utility District, Columbia River People's Utility District, Inland Power and Light Company, Northwest Public Power Association, Northwest Requirements Utilities, Pacific Northwest Generating Cooperative, Public Power Council, Public Utility District No. 1 of Snohomish County, and Tillamook People's Utility District.

¹⁵ Public Service Electric and Gas Company, PSEG Fossil LLC, and PSEG Nuclear LLC.

¹⁶ Constellation Energy Group, Inc., Baltimore Gas & Electric Company, Constellation Energy Commodities Group, Inc., Constellation Energy Control and Dispatch, LLC, Constellation NewEnergy, Inc., and Constellation Power Source Generation, Inc. (together, Constellation) and Constellation Energy Nuclear Group, LLC (CENG).

¹⁷ *See infra*, P 15, P 18, P 20.

in the Protection System maintenance and testing standard that were identified by the NOPR within the Reliability Standards development process, and directs, in part, that the concerns identified by the NOPR with regard to reclosing relays be addressed within the reinitiated PRC-005 revisions.

A. Maintenance and Testing of Auxiliary and Non-Electrical Sensing Relays

12. In the NOPR, the Commission noted a concern that the proposed interpretation may not include all components that serve in some protective capacity.¹⁸ The Commission's concerns included the proposed interpretation's exclusion of auxiliary and non-electrical sensing relays. The Commission proposed to direct NERC to develop a modification to the Reliability Standard to include any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature, including devices designed to sense or take action against any abnormal system condition that will affect reliable operation, and to initiate appropriate control circuit actions.

13. In their comments NERC, EEI, Joint Cities, Manitoba, NRECA, ITC, MidAmerican, and PSEG expressed varying levels of disagreement with the NOPR's proposed directive. The disagreements are based on a concern that the proposed directive

¹⁸ NOPR at P 11-14.

will create an increase in scope that will capture many items not used in BES protection. NERC is concerned the scope of this proposed directive is so broad that any device that is installed on the Bulk-Power System to monitor conditions in any fashion may be included.¹⁹ NERC states that many of these devices are advisory in nature and should not be reflected within NERC Reliability Standards if they do not serve a necessary reliability purpose.²⁰ NERC does not believe it is necessary for the Commission to issue a directive to address this issue. Instead, NERC proposes to develop, either independently or in association with other technical organizations such as IEEE, one or more technical documents which:

1. describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and
 2. propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.²¹
14. NERC states that these technical documents will address those protective relays that are necessary for the reliable operation of the Bulk-Power System and will allow for differentiation between protective relays that detect faults from other devices that monitor

¹⁹ NERC February 25, 2011 Comments at 7.

²⁰ *Id.*

²¹ *Id.*

the health of the individual equipment and are advisory in nature (e.g., oil temperature). Following development of the above-referenced document(s), NERC states that it will “propose a new or revised standard (e.g. PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals.”²² Accordingly, NERC proposes to “add this issue to the Reliability Standards issues database for inclusion in the list of issues to address the next time the PRC-005 standard is revised.”²³

15. The Commission accepts NERC’s proposal, and directs NERC to file, within sixty days of publication of this Final Rule, a schedule for informational purposes regarding the development of the technical documents referenced above, including the identification of devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation. NERC shall include in the informational filing a schedule for the development of the changes to the standard that NERC stated it would propose as a result of the above-referenced documents.²⁴ NERC should update its schedule when it files its annual work plan.

²² *Id.*

²³ *Id.*

²⁴ *Id.* at 7, 8.

B. Reclosing Relays

16. In the NOPR, the Commission noted that while a reclosing relay is not identified as a specific component of the Protection System, if it either is used in coordination with a Protection System to achieve or meet system performance requirements established in other Commission–approved Reliability Standards, or can exacerbate fault conditions when not properly maintained and coordinated, then excluding the maintenance and testing of these reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the Bulk-Power System.²⁵ Accordingly, the Commission proposed that NERC modify the Reliability Standard to include the maintenance and testing of reclosing relays affecting the reliability of the Bulk-Power System.

17. NERC, EEI, IRC, ITC MidAmerican, NRECA, and PSEG opposed the NOPR’s directive to include reclosing relays. In general, commenters state that reclosing relays used for stability purposes are already included in maintenance and testing programs, and that reclosing relays that are primarily used to minimize customer outages times and maximize availability of system components should not be included. PSEG and MidAmerican contend that the NERC standards development process should be utilized

²⁵ NOPR at P 15.

to determine the maintenance and testing of those reclosing relays that affect the reliability of the Bulk-Power System.

18. ISO/RTO contends that the primary purpose of reclosing relays is to allow more expeditious restoration of lost components of the system, not to maintain the reliability of the Bulk-Power System. Therefore, ISO/RTO maintains that automatic reclosing relays should not be subject to the NERC Reliability Standard for relay maintenance and testing. MidAmerican states that there are only limited circumstances when a reclosing relay can actually affect the reliability of the Bulk-Power System. MidAmerican contends that it would be overbroad for the Commission to direct a modification to the standard that encompasses all reclosing relays that can “exacerbate fault conditions when not properly maintained and coordinated,” as this would improperly include many types of reclosing relays that do not necessarily affect the reliability of the Bulk-Power System.

19. ITC agrees with the Commission’s proposal that reclosing relays that are required for system stability should be maintained and tested under Requirement R1 of PRC-005-1. However, ITC contends that since most bulk electric system automatic reclosing relay systems are applied to minimize customer outage times and to maximize availability of system components, only some “high speed” reclosing relays will affect the reliability of the Bulk-Power System. Therefore, ITC proposes that the Commission should direct NERC to draft specific requirements or selection criteria that should be used in

identifying the types of re-closing relays for maintenance and testing under Requirement R1 of PRC-005-1.²⁶

20. While NRECA notes that reclosing relays operate to restore, not protect a system, NRECA also notes that there are reclosing schemes that directly affect and are required for automatic stability control of the system, but that such schemes are already covered under Special Protection Schemes that are subject to reliability standards. NRECA, notes that some transmission operators do not allow reclosing relays on the bulk power system to remove the possibility of reclosing in on a permanent fault, thus avoiding further potential damage to the bulk power system.²⁷

21. Similarly, NERC comments that in most cases reclosing relays cannot be relied on to meet system performance requirements because of the need to consider the impact of auto-reclosing into a permanent fault; however, NERC states that applications that may exist in which automatic restoration is used to meet system performance requirements following temporary faults. NERC comments that where reclosing relays are applied to meet performance requirements in approved NERC Reliability Standards, or where automatic restoration of service is fundamental to derivation of an Interconnection Reliability Operating Limit (IROL), it is reasonable to require maintenance and testing of

²⁶ ITC Comments at 7.

²⁷ NRECA Comments at 13-14.

auto-reclosing relays.²⁸ However, NERC does not believe it is necessary for the Commission to issue a directive.²⁹ NERC states that the proposed revisions to Reliability Standard PRC-005-1 that are under development include maintenance of reclosing devices that are part of Special Protection Systems.³⁰ NERC proposes “to add the remaining concerns relating to this issue to the Reliability Standards issues database for inclusion in the list of issues to address the next time Reliability Standard PRC-005 is revised.”³¹

22. As NERC and other commenters point out, reclosing relays are used in a broad range of applications; e.g., meet system performance requirements in approved Reliability Standards, derivation of IROLs, maintain system stability, minimize customer outage times, to maximize availability of system components, etc. While commenters acknowledge that reclosing relays have several applications, commenters also appear to be divided on which applications, if any, should be included in a maintenance and testing program.

²⁸ NERC February 25, 2011 Comments at 9.

²⁹ TAPs urges the Commission to use its authority pursuant to section 215(d)(5) in circumstances where there is a clear need for such a directive.

³⁰ *Id.*

³¹ *Id.*

23. The NOPR raised a concern that excluding the maintenance and testing of reclosing relays that can exacerbate fault conditions when not properly maintained and coordinated will result in a gap affecting Bulk-Power System reliability.³² We agree with MidAmerican that while there are only limited circumstances when a reclosing relay can actually affect the reliability of the Bulk-Power System, there are some reclosing relays, e.g., whose failure to operate or that misoperate during an event due to lack of maintenance and testing, may negatively impact the reliability of the Bulk-Power System.³³ We agree with NERC that where reclosing relays are applied to meet performance requirements in approved NERC Reliability Standards, or where automatic restoration of service is fundamental to derivation of an Interconnection Reliability Operating Limit (IROL), it is reasonable to require maintenance and testing of auto-reclosing relays.

24. In the NOPR we stated that a misoperating or miscoordinated reclosing relay may result in the reclosure of a Bulk-Power System element back onto a fault or that a misoperating or miscoordinated reclosing relay may fail to operate after a fault has been cleared, thus failing to restore the element to service. As a result, the reliability of the

³² NOPR at P 15, noting one such outage resulting in the loss of over 4,000 MW of generation and multiple 765 kV lines.

³³ MidAmerican Comments at 6.

Bulk-Power System would be affected. In addition, misoperated or miscoordinated relays may result in damage to the Bulk-Power System. For example, a misoperation or miscoordination of a reclosing relay causing the reclosing of Bulk-Power System facilities into a permanent fault can subject generators to excessive shaft torques and winding stresses and expose circuit breakers to systems conditions less than optimal for correct operation, potentially damaging the circuit breaker.³⁴

25. While some commenters argue that reclosing relays do not affect the reliability of the Bulk-Power System, the record supports our concern. For example, we note NERC's concern regarding the "... need to consider the impact of autoreclosing into a permanent fault." We also note NRECA's comments that "... some transmission operators do not allow reclosing on the bulk electric system facilities to remove the opportunity of closing in on a permanent fault" and "... by its [automatic reclosing] use a utility understands the potential for further damage that may occur by reclosing."³⁵ Because the misoperation or miscommunication of reclosing relays can exacerbate fault conditions, we find that

³⁴ NERC System Protection and Control Subcommittee, "Advantages and Disadvantages of EHV Automatic Reclosing," December 9, 2009, p. 14.

³⁵ NRECA Comments at 13.

reclosing relays that may affect the reliability of the Bulk-Power System should be maintained and tested.³⁶

26. For the reasons discussed above, we conclude that it is important to maintain and test reclosing relays that may affect the reliability of the Bulk-Power System. We agree with ITC that specific requirements or selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System. As MidAmerican suggests, the standard should be modified, through the Reliability Standards development process, to provide the Transmission Owner, Generator Owner, and Distribution Provider with the discretion to include in a Protection System maintenance and testing program only those reclosing relays that the entity identifies as having an affect on the reliability of the Bulk-Power System.

27. We note that the original project to revise Reliability Standard PRC-005 failed a recirculation ballot in July of 2011. The project was subsequently reinitiated to continue the efforts to develop Reliability Standard PRC-005-2. Given that the project to draft proposed revisions to Reliability Standard PRC-005-1 continues in this reinitiated effort, and the importance of maintaining and testing reclosing relays, we direct NERC to include maintenance and testing of reclosing relays that can affect the reliable operation

³⁶ As NERC notes, there may be applications of reclosing relays where the misoperation or miscommunication may does not have a detrimental effect on the reliability of the Bulk-Power System.

of the Bulk-Power System, as discussed above, within these reinitiated efforts to revise Reliability Standard PRC-005.³⁷

C. DC Control Circuitry and Components

28. In the NOPR, the Commission explained its understanding that a maintenance and testing program for DC control circuitry would include all components of DC control circuitry necessary for ensuring Reliable Operation of the Bulk-Power System, and that not establishing the specific requirements of such a maintenance and testing program results in a gap in the maintenance and testing of Protection System components.³⁸

29. Joint Cities, MidAmerican, and NRECA expressed concern that the NOPR's directive is too broad and unnecessarily burdensome. NERC agrees that maintenance and testing should be required for all DC control circuitry.³⁹ NERC further stated that draft standard PRC-005-2 being developed in Project 2007-17 "includes extensive, specific maintenance activities (with maximum maintenance intervals) related to the DC control

³⁷ On December 13, 2011, NERC submitted its Standards Development Plan for 2012-2014. NERC estimates that Project 2007-17 will be completed in the second quarter of 2012. By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.

³⁸ NOPR at P 16.

³⁹ NERC February 25, 2011 Comments at 10.

circuits.”⁴⁰ The Commission accepts NERC’s commitment to include the development of specific requirements of such a maintenance and testing program described above in Project 2007-17.⁴¹

VII. Information Collection Statement

30. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.⁴² The Commission submits reporting and recording keeping requirements to OMB under section 3507 of the Paperwork Reduction Act of 1995.⁴³

31. As stated above, the Commission previously approved, in Order No. 693, the Reliability Standard that is the subject of the current Final Rule. This Final Rule accepts an interpretation of the currently approved Reliability Standard. The interpretation of the current Reliability Standard at issue in this final rule is not expected to change the reporting burden or the information collection requirements. The informational filing

⁴⁰ *Id.*

⁴¹ As previously noted, NERC estimates that Project 2007-17 will be completed by the second quarter of 2012. By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.

⁴² 5 CFR 1320.

⁴³ 44 U.S.C. 3507.

required of NERC is part of currently active collection FERC-725 and does not require additional approval by OMB.

32. We will submit this final rule to OMB for informational purposes only.

VIII. Environmental Analysis

33. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.⁴⁴ The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.⁴⁵ The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

IX. Regulatory Flexibility Act

34. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities.⁴⁶ The RFA mandates consideration of regulatory alternatives that

⁴⁴ *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

⁴⁵ 18 CFR 380.4(a)(2)(ii).

⁴⁶ 5 U.S.C. 601-612.

accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.⁴⁷ The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.⁴⁸ The RFA is not implicated by this Final Rule because the interpretation accepted herein does not modify the existing burden or reporting requirements. Because this Final Rule accepts an interpretation of the currently approved Reliability Standard, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

X. Document Availability

35. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (<http://www.ferc.gov>) and in FERC's Public Reference Room during normal business

⁴⁷ 13 CFR 121.201.

⁴⁸ *Id.* n.1.

hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

36. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

37. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

XI. Effective Date and Congressional Notification

38. This Final Rule is effective 30 days from publication in Federal Register. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of subjects in 18 CFR Part 40

Applicability
Mandatory Reliability Standards
Availability of Reliability Standards

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

July 30, 2012

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: Informational Filing in Compliance with Order No. 758 – Interpretation of Protection System Reliability Standard, Docket No. RM10-5-000

Dear Ms. Bose,

On February 3, 2012, the Federal Energy Regulatory Commission (“Commission”) issued Order No. 758, approving the North American Electric Reliability Corporation (“NERC”) interpretation of Requirement R1 of Commission-approved Reliability Standard PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing.¹

In Order No. 758, the Commission also accepted NERC’s commitments to address the concerns in the Protection System Maintenance and Testing standard within the Reliability Standards development process, and directed NERC to file, by July 30, 2012, either a completed project, or an informational filing providing “a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.”²

This informational filing is submitted in compliance with Order No. 758. On May 10, 2012, the NERC Standards Committee approved a Standard Authorization Request to revise Reliability Standard PRC-005 to address the maintenance and testing of reclosing relays in NERC Project 2007-17.

The NERC Standards Committee noted that PRC-005-2 is in the final stages of the development process, having passed successive ballot with 79 percent approval on June 27, 2012. NERC staff anticipates that PRC-005-2 will be presented for approval at the November NERC Board of Trustees meeting. Therefore, in recognition of the consensus that has been reached, the NERC Standards Committee determined that the drafting team should complete work on PRC-005-2 currently under development and immediately thereafter begin work on the necessary revisions to address reclosing relays, which would be reflected in a to be proposed PRC-005-3.

¹ *Interpretation of Protection System Reliability Standard*, 138 FERC ¶ 61,094 (2012), (“Order No. 758”).

² Order No. 758 at fn 37.

The revised schedule for Project 2007-17 is provided herein as **Attachment A**. NERC intends to proceed in accordance with the Project 2007-17 schedule.

Sincerely,

/s/ Willie L. Phillips

Willie L. Phillips

Attorney

North American Electric Reliability Corporation

cc: Gerald W. Cauley, NERC President and Chief Executive Officer
Charles A. Berardesco, NERC Senior Vice President and General Counsel
Holly A. Hawkins, NERC Assistant General Counsel
Official service lists in Docket No. RM10-5-000

ATTACHMENT A

NERC Proposed Project 2007-17 Schedule to Revise Reliability Standard PRC-005 to Address the Maintenance and Testing of Reclosing Relays in Compliance with Order No. 758

January 2013	Standard Drafting Team continues work revising PRC-005 standard to address reclosing relays
April-May 2013	Initial draft PRC-005 standard posted for industry comment
July-August 2013	Revised draft PRC-005 standard posted for industry comment and initial ballot
October-November 2013	Revised PRC-005 standard posted for successive ballot
January 2014	Revised PRC-005 standard posted for successive ballot
March 2014	Revised PRC-005 standard posted for recirculation ballot
May 2014	Proposed PRC-005 standard submitted for NERC Board of Trustees approval
July 2014	Petition for approval of PRC-005 filed with FERC

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Considerations for Maintenance and Testing of Autoreclosing Schemes

System Analysis and Modeling Subcommittee
System Protection and Control Subcommittee

November 2012

RELIABILITY | ACCOUNTABILITY



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NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to enhance the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.¹

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

NERC Regional Entities	
FRCC Florida Reliability Coordinating Council	SERC SERC Reliability Corporation
MRO Midwest Reliability Organization	SPP RE Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	TRE Texas Reliability Entity
RF ReliabilityFirst Corporation	WECC Western Electricity Coordinating Council

¹ As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the “electric reliability organization” under Alberta’s Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l’énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC’s reliability standards are also mandatory in Nova Scotia and British Columbia. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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This technical document was approved by the NERC Planning Committee on November 14, 2012.

Introduction

On February 3, 2012, the Federal Energy Regulatory Commission (FERC) issued Order No. 758² approving an interpretation of NERC Reliability Standard PRC-005-1, Transmission and Generation Protection System Maintenance and Testing. In addition to approving the interpretation, the Commission directed that concerns identified in the preceding Notice of Proposed Rulemaking (NOPR) be addressed within the reinitiated PRC-005 revisions.

The concerns raised in the NOPR pertain to automatic reclosing (autoreclosing) relays that are either “used in coordination with a Protection System to achieve or meet system performance requirements established in other Commission-approved Reliability Standards, or can exacerbate fault conditions when not properly maintained and coordinated,” in which case “excluding the maintenance and testing of these reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the Bulk-Power System.”³ To address these concerns, the Commission concludes that “specific requirements or selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System.”⁴

This report provides technical input from the NERC System Analysis and Modeling Subcommittee (SAMS) and the System Protection and Control Subcommittee (SPCS), both subcommittees of the NERC Planning Committee, to support the Project 2007-17 standard drafting team assigned to modify PRC-005. This report recommends technical bases to identify those autoreclosing applications that may affect reliability of the bulk power system. Such applications should be included in the Applicability section of PRC-005 to address the directives in Order No. 758.

² See FERC Order No. 758, [Interpretation of Protection System Reliability Standard](#), 138 FERC ¶ 61,094.

³ *Id.* at P. 16.

⁴ *Id.* at P. 26.

Considerations for Applicability of PRC-005

Autoreclosing is utilized on transmission systems to restore transmission elements to service following automatic circuit breaker tripping. When an autoreclosing application may affect reliability of the bulk power system, the autoreclosing relay⁵ should be included in the applicability of PRC-005.

The concerns identified by the Commission in Order No. 758 can be grouped into two categories:

- situations in which autoreclosing fails to operate when required to maintain bulk power system reliability; and
- situations in which autoreclosing operates in manner that is not consistent with its design, adversely affecting reliability of the bulk power system.

The following sections address these two categories of concern.

Applications to Improve Bulk Power System Performance

Consideration of Autoreclosing to Increase Operating Limits

Planning and operation of the bulk power system must consider autoreclosing applications.⁶ Autoreclosing following automatic circuit breaker tripping may be successful if the condition that initiated the tripping (e.g., a fault) is no longer present, or it may be unsuccessful if the condition is still present in which case the circuit breaker will trip again. While successful autoreclosing enhances reliability of the bulk power system, autoreclosing into a permanent fault may adversely affect reliability. Since the potential for autoreclosing into a permanent fault exists for any application, it is not possible to depend on successful autoreclosing as a means to meet the system performance requirements in the NERC Reliability Standards or to increase the transfer limit associated with an Interconnection Reliability Operating Limit⁷ (IROL).

Single-pole tripping and autoreclosing also may be used to minimize the impact to the system for a single-phase fault; however, the same issues exist for single-pole autoreclosing with regard to the potential for an autoreclose into a permanent fault after which all three poles are tripped. In the event an autoreclosing relay fails to initiate reclosing after a single-pole trip, protective functions will detect the condition and trip all three poles after a time delay.

SAMS and SPCS have not identified an application in which autoreclosing is used in coordination with a protection system to meet the system performance requirements in a NERC Reliability

⁵ Autoreclosing relays in this context include dedicated autoreclosing relays and the autoreclosing function in multi-function relays.

⁶ For example, TPL-001-2, adopted by the NERC Board of Trustees on August 4, 2011, requires that analyses include the impact of subsequent successful high-speed autoreclosing and unsuccessful high-speed autoreclosing into a fault where high-speed autoreclosing is utilized.

⁷ Capitalized as referenced in the NERC Glossary of Terms.

Standard or in establishing an IROL. As discussed above, the need to consider autoreclosing into a permanent fault precludes dependency on autoreclosing for this purpose. SAMS and SPCS therefore recommend that no modification is necessary to the applicability of PRC-005 to address autoreclosing applications necessary for bulk power system performance.

Autoreclosing as Part of a Special Protection System

Special Protection Systems⁸ (SPS) may be applied to meet system performance requirements in the NERC Reliability Standards or to increase the transfer limit associated with an IROL. When autoreclosing is included as an integral part of such a SPS, a failure of the reclosing function may adversely impact bulk power system reliability. NERC Reliability Standard PRC-005-2⁹ includes minimum maintenance activities and maximum intervals for SPS. SAMS and SPCS recommend that PRC-005 be modified to explicitly address maintenance and testing of autoreclosing relays applied as an integral part of a SPS.

Applications to Aid Restoration

Autoreclosing typically is installed to alleviate the burden on operators of manually restoring transmission lines. Autoreclosing also provides improved availability of overhead transmission lines. The degree to which availability is improved depends on the nature of the fault (permanent or temporary) and on transmission operator practices for manually restoring lines. While faster restoration of transmission lines following temporary faults does provide an inherent reliability benefit, this section addresses applications that are not necessary to meet system performance requirements in NERC Reliability Standards. In these applications it is possible for undesired operation of the autoreclosing scheme, not consistent with its design, to adversely affect system reliability. The following sections discuss credible failure modes that may lead to undesired operation and the associated potential reliability impacts to the bulk power system, to identify applications that should be included in the Applicability section of PRC-005.

Credible Failure Modes of Autoreclosing Schemes

This section discusses credible failure modes of autoreclosing schemes. These failure modes are assessed in the next section to identify which may impact reliability of the bulk power system. Applications for which one or more of these failure modes could adversely affect reliability will be provided to the Project 2007-17 standard drafting team to support development of revisions to PRC-005 directed in Order No. 758.

There are many different types of autoreclosing relays. Autoreclosing relays may be electromechanical (and comprised of discrete components), solid state, or microprocessor-based and may be applied in a variety of autoreclosing schemes. Regardless of the type of autoreclosing scheme or vintage of design of the autoreclosing relay, there are a few main characteristics shared by most autoreclosing relays. These include:

⁸ Capitalized as referenced in the NERC Glossary of Terms.

⁹ PRC-005-2 achieved 81.08 percent quorum and 80.51 percent approval in a recirculation ballot that ended October 24, 2012.

- **Supervision Functions:** Supervising elements typically monitor one or more voltage phases to determine if a circuit is energized (live), de-energized (dead), or in synchronism with another circuit, etc. Other types of supervision may be used to perform selective autoreclosing; e.g., autoreclosing is blocked for the detection of a three-phase fault, or for the loss of a communication channel. In some applications, autoreclosing is unsupervised.
- **Timing Functions:** Timing elements perform various timing duties with the most important being the desired time delay to issue a circuit breaker close; the minimum time delay being dictated by de-ionization time. In some applications, autoreclosing is initiated by protective relaying and issues a close signal with little or no intentional time delay.
- **Output Function:** The output function is typically some type of relay with contacts that close and apply DC voltage to the close circuit to effect a circuit breaker close.

When analyzing autoreclosing relay failure modes, the functions described above are the ones most likely to lead to a failure. The failures can be analyzed without a detailed discussion of the many variations of autoreclosing logic that may be implemented throughout North America. The main failure modes of autoreclosing relays are:

- **Supervision Function Failures:** A failed voltage supervision function that requires a dead line to reclose may incorrectly interpret that the monitored circuit is live and consequently not issue a close signal to a circuit breaker as designed. Conversely, a failed voltage supervision function that requires a live line to reclose may incorrectly interpret that a dead circuit is live and, therefore, incorrectly issue a close signal to a circuit breaker. Further, failure of a synchronism check function may allow a close when static system angles are greater than designed, or inhibit a close when static system angles are less than designed.
- **Timing Function Failures:** Where intentional time delays are used, the time delay circuits may fail and issue a close with no time delay. Failure of the time delay circuits may also inhibit the autoreclosing relay from issuing a close signal.
- **Output Function Failures:** The output relay contacts may fail to close and thus no close signal will be issued to a circuit breaker. The output relay contacts may also fail in the closed position (“weld shut”) and send a constant close signal to a circuit breaker. Solid state outputs can exhibit both of these failure modes. This failure mode can result in one of two possible scenarios depending on the circuit breaker closing circuit design and whether the constant close signal occurs prior to tripping or during the act of reclosing the circuit breaker. One scenario is that no reclose will occur. The second scenario will result in only one reclose being attempted.

Thus, to assess the potential impact of an autoreclosing relay failure on the power system, the following types of failures should be considered:

- No close signal is issued under conditions that meet the intended design conditions. This is the most common failure mode and includes the vast majority of autoreclosing failures.
- A close signal is issued with no time delay or with less time delay than is intended.
- A constant or sustained close signal is issued. In this case, a multi-shot reclose scheme may attempt to reclose only once.
- A close signal is issued for conditions other than the intended supervisory conditions.

Potential Reliability Impacts

In this section each of the identified autoreclosing failure modes is analyzed to assess the potential for adverse impact to bulk power system reliability and the circumstances under which impacts may occur.

1. No close signal is issued under conditions that meet the intended design conditions: A failure to autoreclose would result in a failure to restore a single power system element. The system already must be planned and operated considering that autoreclosing will be unsuccessful. Thus, the impact to power system reliability for this failure mode results in a condition the system is designed to withstand, and therefore this failure mode does not create any additional considerations for inclusion of autoreclosing relays in PRC-005 beyond those related to SPS as discussed in the previous section.
2. A close signal is issued with no time delay or with less time delay than is intended: This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic.

The potential reliability impacts of this failure mode are damage to generators and generator instability. Autoreclosing logic typically is selected to reenergize a dead circuit remote from generating units or strong sources to avoid adverse impacts associated with autoreclosing into a permanent fault. Typically when autoreclosing is applied at a generating station it is only for live-line conditions with synchronism check; however, applications do exist where autoreclosing from a generating station is used such as transmission lines between two generating plants, or radial lines that cannot be energized from another source. Where autoreclosing is applied at or in proximity to a generating station the potential for this failure mode exists.

Premature autoreclosing has the potential to cause generating unit loss of life due to shaft fatigue. Accepted industry guidance is that planned switching operations, such as simple line restoration, should be conducted in a way that avoids significant contribution to cumulative shaft fatigue. Entities typically implement this guidance at generating stations by using time delayed autoreclosing to allow shaft oscillations to dampen, and/or live line autoreclosing or live bus-live line autoreclosing with synchronism check supervision to

minimize shaft torque. By conducting planned switching in this manner, nearly all of the fatigue capability of the shaft is preserved to withstand the impact of unplanned and unavoidable disturbances such as faults, fault clearing, reclosing into system faults, and emergency line switching. Premature autoreclosing due to a supervision failure is a small subset of autoreclosing failures (the overwhelming majority of autoreclosing failures are failure to close) and is an infrequent unplanned disturbance. As a result, it is not necessary to consider the incremental loss of life that may occur for this infrequent event as the basis for whether to include maintenance and testing of autoreclosing relays in PRC-005.

Premature autoreclosing also has the potential to cause generating unit or plant instability. NERC Reliability Standards require consideration of loss of the largest generating unit within a Balancing Authority Area¹⁰; therefore, generation loss would not impact reliability of the bulk power system unless the combined capacity loss exceeds the largest unit within the Balancing Authority Area. Including maintenance and testing of autoreclosing relays in PRC-005 would therefore be appropriate for applications at or in proximity to generating plants with capacity exceeding the largest unit within the Balancing Authority Area. In this context proximity is defined as one bus away if the bus is within 10 miles of the generating plant. Transmission line impedance on the order of 1 mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

At these locations, maintenance and testing of autoreclosing relays should be subject to PRC-005, unless the equipment owner can demonstrate to the Transmission Planner that this failure mode would not result in tripping generating units with combined capacity greater than the largest unit within the Balancing Authority Area. This demonstration should be based on simulation of a close-in three-phase fault for twice the normal clearing time (capturing a minimum trip-close-trip time delay).

3. A constant or sustained close signal is issued: This failure mode can result in one of two possible scenarios depending on the circuit breaker closing circuit design and whether the constant close signal occurs prior to tripping or during the act of reclosing the circuit breaker. One scenario is that no reclose will occur. The second scenario will result in only one reclose being attempted. This scenario results in the worse impact; however this results in an outcome similar to failure mode No. 1 – less reclose attempts than planned. Neither of these failure modes creates any additional considerations for inclusion of autoreclosing relays in PRC-005.
4. A close signal is issued for conditions other than the intended supervisory conditions: This failure mode can result in two different scenarios.

The first scenario is autoreclosing into a dead line with a fault when dead-line closing was not intended. Similar to failure mode No. 2 discussed above, the potential reliability

¹⁰ Capitalized as referenced in the NERC Glossary of Terms.

impacts of this failure mode are instability and damage to generating units. The incidence of this failure mode is similar to failure mode No. 2 and therefore concern may be limited to the potential loss of generating units with combined capacity that exceeds the largest unit within the Balancing Authority Area. Including maintenance and testing of autoreclosing relays in PRC-005 would therefore be appropriate for applications at or in proximity to generating units as noted above. The primary difference between this scenario and failure mode No. 2 is this failure mode does not include a timing failure. As such both this scenario and failure mode No. 2 can lead to unintended autoreclosing into fault; however, the timing of the undesired autoreclosure in this scenario will occur after any intentional time delay included in the autoreclosing relay. For this reason a separate test is not necessary to exclude applications from maintenance and testing under PRC-005. Application of the test described for failure mode No. 2 adequately addresses this failure mode.

The second scenario is autoreclosing into a live line with an angle greater than the acceptance angle necessary to prevent potential equipment damage. The potential reliability impact of this failure mode is damage to generating units. As noted in the discussion of failure mode No. 2, accepted industry guidance is that planned switching operations, such as simple line restoration, should be conducted in a way that avoids significant contribution to cumulative shaft fatigue. By conducting planned switching in this manner, nearly all of the fatigue capability of the shaft is preserved to withstand the impact of unplanned and unavoidable disturbances such as faults, fault clearing, reclosing into system faults, and emergency line switching. Undesired autoreclosing at an angle greater than the sync-check acceptance angle due to a supervision failure is a small subset of autoreclosing failures and is an infrequent unplanned disturbance. As a result, it is not necessary to consider the incremental loss of life that may occur for this infrequent event as the basis for whether to include maintenance and testing of autoreclosing relays in PRC-005.

Maintenance Intervals and Activities

The SPCS reviewed the maximum maintenance intervals and minimum maintenance activities proposed in reliability standard PRC-005-2. Specifically, the SPCS reviewed Table 1-1 which is applicable to protective relays and Table 1-5 which is applicable to control circuitry associated with protective functions (excluding distributed UFLS and distributed UVLS). The SPCS review focused on whether any substantive differences exist between protective relays and autoreclosing relays, or between control circuitry associated with protective functions and circuitry associated with autoreclosing schemes, that would warrant different intervals or activities for maintenance of autoreclosing components.

Autoreclosing Relays

The SPCS concluded that electromechanical, solid-state, and microprocessor based autoreclosing relays are substantially the same with respect to design and manufacturing as their protective relay counterparts. As such, the SPCS recommends that the maximum intervals defined in Table 1-1 of PRC-005-2 should also be applicable to autoreclosing relays that may be subject to future versions of the standard.

The SPCS also assessed the maintenance activities included in Table 1-1 of PRC-005-2 and concluded that the activities are analogous to activities performed during maintenance and testing of autoreclosing relays and therefore Table 1-1 should be applied to autoreclosing relays that may be subject to future versions of the standard. For example, the activity to test and, if necessary calibrate, non-microprocessor relays would be applicable to testing and calibration of electromechanical and solid-state autoreclosing relays, and the activity to verify acceptable measurement of power system input values would be applicable to verification of permissive inputs used for voltage supervision and synchronism check.

Autoreclosing Control Circuitry

Similarly, the SPCS assessed the maintenance intervals and activities included in Table 1-5 of PRC-005-2 and concluded that the intervals and activities for maintaining control circuitry for autoreclosing schemes should be similar to those established for maintaining control circuitry associated with protective functions. The SPCS recommends that Table 1-5 should be applicable to control circuitry associated with autoreclosing relays that may be subject to future versions of the standard. The SPCS also recommends that the standard drafting team include minimum maintenance activities and maximum maintenance intervals for autoreclosing control circuitry that parallel the maintenance activities and intervals established for protective function control circuitry. It should be noted that, consistent with control circuitry defined for protective functions, the SPCS does not consider internal breaker control circuitry (e.g., anti-pump and coil interlock circuits) to be associated with autoreclosing component maintenance. Since the failure to close may represent a risk to reliability when breaker closing is integral to operation of an SPS, the closing coil should be considered in PRC-005. For use within a revision to PRC-005, control circuitry of autoreclosing schemes might be defined as:

“Control circuitry associated with autoreclosing schemes including the close coil, but excluding breaker internal controls such as anti-pump and various interlock circuits.”

Recommendations

SAMS and SPCS recommend the following guidance for future development of NERC Reliability Standard PRC-005, *Transmission and Generation Protection System Maintenance and Testing*, to address the concerns stated in FERC Order No. 758.

1. Modify PRC-005 to explicitly address maintenance and testing of autoreclosing relays applied as an integral part of a SPS.
2. Modify PRC-005 to include maintenance and testing of autoreclosing relays at or in proximity to generating plants at which the total installed capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area.
 - In this context, define proximity as substations one bus away if the substation is within 10 miles of the plant.
 - Include a provision to exclude autoreclosing relays if the equipment owner can demonstrate to the Transmission Planner that a close-in three-phase fault for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of generation in the interconnection exceeding the largest unit within the Balancing Authority Area where the autoreclosing is applied.
3. Base minimum maintenance activities and maximum intervals on the activities and intervals in PRC-005-2.
 - Develop minimum maintenance activities and maximum intervals for autoreclosing relays similar to Table 1-1.
 - Develop minimum maintenance activities and maximum intervals for control circuitry of autoreclosing schemes similar to Table 1-5.
 - For the purpose of PRC-005, define control circuitry of autoreclosing schemes as: “Control circuitry associated with autoreclosing schemes including the close coil, but excluding breaker internal controls such as anti-pump and various interlock circuits.”

Appendix A – System Analysis and Modeling Subcommittee Roster

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ISO New England

K. R. Chakravarthi

Vice Chair

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Southern Company Services, Inc.

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RE – FRCC

Manager, Transmission Planning Florida
Progress Energy Florida

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RE – FRCC – Alternate

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Supervising Engineer, Transmission Planning
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Southwest Power Pool, Inc.

Kenneth A. Donohoo

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Digaunto Chatterjee

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National Rural Electric Cooperative Association

Eric Mortenson, P.E.

Investor-Owned Utility

Principal Rates & Regulatory Specialist
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Amos Ang, P.E.

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Engineer, Transmission Interconnection Planning
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Greg Henry

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Senior Performance and Analysis Engineer
NERC

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Southern Company

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RE – FRCC

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Miroslav Kostic

Canada Provincial

P&C Planning Manager, Transmission
Hydro One Networks, Inc.

Sungsoo Kim

Canada Provincial

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Jonathan Sykes

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Pacific Gas and Electric Company

Charles W. Rogers

Transmission Dependent Utility

Principal Engineer
Consumers Energy Co.

Joe T. Uchiyama

U.S. Federal

Senior Electrical Engineer
U.S. Bureau of Reclamation

Daniel McNeely

U.S. Federal – Alternate

Engineer - System Protection and Analysis
Tennessee Valley Authority

Philip J. Tatro

NERC Staff Coordinator

Senior Performance and Analysis Engineer
NERC

Standards Announcement **Correction**

Project 2007-17.2: PRC-005-3 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)

PRC-005-3 Formal Comment Period Open: April 5, 2013 – May 6, 2013

SAR Informal Comment Period Open: April 5, 2013 – May 6, 2013

[Now Available](#)

A Standard Authorization Request (SAR) for PRC-005 and draft of **PRC-005-3** – Protection System and Automatic Reclosing Maintenance are each posted for a 30-day comment period through **8 p.m. Eastern on Monday, May 6, 2013.**

This phase of the project is limited to addressing a regulatory directive from FERC Order No. 758. The SAR is being posted for an informal comment period with no requirement for the standard drafting team to provide a formal response. The standard is being posted for a formal comment period and a formal response to those comments will be prepared.

Background information for this project can be found on the [project page](#).

Instructions for Commenting

The comment period for the SAR and draft PRC-005-3 is open through **8 p.m. Eastern on Monday, May 6, 2013.** Please use the following electronic forms to submit comments:

[Comment Form – SAR](#)

[Comment Form – PRC-005-3](#)

If you experience any difficulties in using the electronic forms, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of each of the comment forms is posted on the [project page](#).

Next Steps

The drafting team will consider all comments and determine whether to make changes to the standard and associated documents. After the standards and associated documents are revised, the drafting team will submit the documents for a quality review and seek acceptance from the NERC Standards Committee to proceed to balloting.

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.*

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

Name (12 Responses)
Organization (12 Responses)
Group Name (12 Responses)
Lead Contact (12 Responses)
Contact Organization (12 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (1 Responses)
Comments (24 Responses)
Question 1 (21 Responses)
Question 1 Comments (23 Responses)
Question 2 (20 Responses)
Question 2 Comments (23 Responses)
Question 3 (21 Responses)
Question 3 Comments (23 Responses)
Question 4 (0 Responses)
Question 4 Comments (23 Responses)

Dominion
Louis Slade
NERC Compliance Policy
No
The SAR goes beyond the directive in that it appears to indicate that all reclosing relays must operate properly in order to maintain BES reliability. The fact is that, in a majority of applications, these relays exist primarily to decrease outage times. The SAR should be limited to only those reclosing relays whose failure to operate correctly could adversely impact reliable operation of the BES. Dominion therefore recommends revising the sentence that reads "The Applicability section of the Standard must be modified to describe explicitly those devices that entities are to maintain in accordance with the revised standard." To read "The Applicability section of the Standard must be modified to describe explicitly those reclosing relays that entities are to maintain in accordance with the revised standard."
No
No
Having reviewed, and generally agree with, the technical study performed jointly by the NERC System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) and subsequently approved by the NERC Planning Committee. We therefore support the OPTIONAL approach shown near the bottom of the SAR as we believe would revise the standard in a way that applies new requirements only to those elements of

the protection system where reclosing is applied it been demonstrated to that an adverse impact on the BES could occur if those element(s) are not included in one or more reliability standard requirements.
Duke Energy
Colby Bellville
Duke Energy
Yes
However we are concerned that the SAR includes possible revision of the definition of Protection System. We don't believe attempting to revise that definition is necessary or advisable.
No
No
The SAR includes statements under "Goals" and "Detailed Description" that the defined term Protection System might be revised as part of this project. Those statements should be removed from the SAR. We strongly believe that the issue of maintenance and testing of any reclosing relays which can affect reliable operation of the BES, can be addressed without attempting to modify the definition of Protection System.
Nazra Gladu
Manitoba Hydro
Yes
No
No
(1) Brief Description of Proposed Standard Modifications/Actions - for completeness, add '(BES)' after Bulk Electric System. (2) Need - capitalize 'misoperation' because it appears in the Glossary of Terms. (3) Need - remove the words "Bulk Electric System" to leave only the acronym, BES because this is the second instance of BES in the document.
John Bee
Exelon and its Affiliates
Yes
No

Yes
FirstEnergy
Larry Raczkowski
FirstEnergy Corp
Yes
No
No
FE supports the referenced SAR as stated.
Bill Fowler
City of Tallahassee
Yes
No
No
None
PacifiCorp
Ryan Millard
PacifiCorp
Yes
No
No
Chris Mattson

Tacoma Power
Yes
No
No
Thomas Foltz
American Electric Power
No
AEP supports the efforts of the drafting team, but is concerned by pursuing a version 3 of this standard before the second version has been approved by FERC. There is significant content within version 3 that was new to version 2, so proper implementation of version 3 would rely on the eventual approval of version 2 in its entirety. The content of version 3 has apparently been drafted with this in mind, however, it over-complicates the implementation plan of version 3 by basing it in-part on the previous and not-yet-approved version, and leaving it vulnerable in the event version 2 does not pass. In addition, it is not clear exactly which sort of automatic reclosing behavior(s) the proposed changes are attempting to prevent. Accidental reclosing? Failure to reclose? Providing clarity on this fundamental question will help industry in providing sound comments and feedback regarding PRC-005-3.
No
AEP is not aware of any regional variances that would be needed as a result of this project.
Yes
AEP believes that it is likely that some of its business practices would need to at least be modified as a result of this project
Pepco Holdings Inc & Affiliates
David Thorne
Pepco Holdings Inc
Yes
No
No

Brad Harris
CenterPoint Energy
Yes
Business practices will be needed to: 1. Document and monitor the generating plant capacity at all Company owned generation interconnection facilities 2. Document and monitor the largest generating unit located in the Balancing Authority 3. Document and monitor the Company owned stations meeting the Applicability attributes described in 4.2.6 of PRC-005-3.
Page 2, Paragraph 2 of the "Need" section of the SAR includes a parenthetical "(installed to meet performance goals of approved NERC Standards)". Recommend deleting this parenthetical statement as the SAMS/SPCS paper concluded on page 2 that "SAMS and SPCS have not identified an application in which auto reclosing is used in coordination with a protection system to meet the system performance requirements in a NERC Reliability Standard or in establishing an IROL".
Kenn Backholm
Public Utility District No.1 of Snohomish County
Yes
No
No
The Public Utility District No.1 of Snohomish County has reviewed and supports this Standard Authorization Request and concluded that the revisions and modifications do not seem impractical or technically unreasonable.
SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
Yes
No
No

None
Andrew Z. Puztai
American Transmission Company
Yes
No
No
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Marcus Pelt
Southern Company Operations Compliance
Yes
No
No
It seems out of order to be posting a draft SAR for informal comment at the same time that the revised standard which is the topic of the SAR is posted for a formal comment period. Further, FERC has not approved PRC-005-2 yet. Any changes required by FERC would affect the draft of PRC-005-3. The proposed standard modification seems premature given that PRC-005-3 SAR is still in draft that PRC-005-2 is not yet approved.
Anthony Jablonski
ReliabilityFirst
No
No, the scope of the SAR only lists three bullet items. It should as a minimum include a lead in sentence similar to the following: PRC-005-2 has been revised to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk Power System. The bullet items do not include the changes made to the Definitions of Terms, Requirements or Compliance sections.
No

No
Can the SDT clarify whether high-speed automatic reclosing is covered within the scope of the SAR?
Tennessee Valley Authority
Brandy Spraker
Transmission Reliability Engineering and Controls
1. Are reclosing relays considered "protective relays"? 2. Are reclosing relays considered part of the "protective system"? 3. Is Table 1-3 applicable to CCVTs that feed only reclosing relays? 4. Does a "reclosing relay" include all relays used to perform all type of automatic reclosing actions, i.e. sync check, dead line, dead bus, and blind reclosing?
Kevin Luke
Georgia Transmission Corporation
Agree
Florida Municipal Power Agency
Frank Gaffney
Florida Municipal Power Agency
Yes
No
Yes
Jonathan Meyer
Idaho Power Company
Yes
No
No

ACES Standards Collaborators
Jason Marshall
ACES
Yes
(1) While we agree the SAR addresses the regulatory directive, we question the value of modifying this standard further when the newest version has yet to be approved. If FERC issues significant directives, the directives could ultimately impact the direction that drafting team should take with modifying the standard to include reclosing relays. Furthermore, because PRC-005 is historically one of the most violated standards primarily because of the zero-defect approach to compliance, we question the value of adding another relay type to the list of relays subject to zero-defect compliance. We are concerned there will be another step function in potential violations that do not ultimately support reliability but detract from reliability because they are focused on documentation. (2) We believe that there are other equally-effective options to address the FERC directives, such as issuing an industry guidance document. If the standard ultimately needs to be modified, a guidance document could allow the drafting team to wait until FERC rules on the PRC-005 to determine if there will be any impacts on adding reclosing relays to the standard.
No
No
(1) We understand that NERC is obligated by law to address all FERC directives issued to them. However, not all FERC directives require the development or revision of a reliability standard. FERC has been clear that other alternatives may be used as long as they are equally effective and efficient. NERC and the drafting team need to consider other alternatives that would produce an equally effective method of ensuring that auto-reclosing relays will be maintained and tested. The drafting team should consider a survey of all registered entities subject to the current PRC-005 standard to see if they include auto-reclosers in their PSMT program. This issue goes back to compliance – whether the entity needs to maintain documentation for each of these devices. A guidance document may be an appropriate solution to handle this FERC directive. (2) Thank you for the opportunity to comment.
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
Yes

Scott Langston
City of Tallahassee
Yes
No
No
None
Bonneville Power Administration
Jamison Dye
Transmission Reliability Program
Yes
No
No

Name (20 Responses)

Organization (20 Responses)

Group Name (16 Responses)

Lead Contact (16 Responses)

Contact Organization (16 Responses)

IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (1 Responses)

Comments (36 Responses)

Question 1 (33 Responses)

Question 1 Comments (35 Responses)

Question 2 (33 Responses)

Question 2 Comments (35 Responses)

Dominion
Louis Slade
NERC Compliance Policy
No
Dominion agrees with most points and conceptually supports the SDT effort to limit additional applicability of this to those facilities identified in the Considerations for Maintenance and Testing of Autoreclosing Schemes report. We are however concerned that footnote 1 requires 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 generation in the Interconnection exceeding the largest unit within the Balancing Authority Area where the Automatic Reclosing is applied." We do not believe that most Distribution Providers or Generator Owners have access to the information, or staff with necessary skills to make such assessments. In fact, we are not confident that entities with such access and skilled staff can make such as assertion. At best we believe an entity with the necessary access and skills could perform an analysis and indicate whether acceptable voltages, flows, angles and stability would be adversely impacted by incorrect operation of an Automatic Reclosing. We do not believe such entity could determine whether or not an incorrect operation would "...result in a total loss of generation in the Interconnection exceeding the largest unit within the Balancing Authority Area where the Automatic Reclosing is applied." We therefore conceptually support most of the standard but request the SDT consider adding a requirement that the Transmission Planner provide a list of those facilities where incorrect operation of Automatic Reclosing has been shown to result in such loss or alternatively to identify facilities where incorrect operation could be shown to result in violation of IROLs.
No
The implementation plan should utilize Transmission Planner (TP) notification to applicable entities rather than simply base the plan on the regulatory approval date to start the implementation timelines. This would allow the notified entities to have the same amount of

time that is currently in the implementation plan upon notification from the Transmission Planner.

Doug Jensen

Vandolah Power Company

Yes

SPP Standards Review Group

Robert Rhodes

Southwest Power Pool

Yes

Would misoperations of automatic reclosing relays as specified in 4.2.6 have to be reported in PRC-004-2?

Yes

Herb Schrayshuen

Self

Yes

No

It will take longer than the team suggests. Suggest a survey to determine a date the industry can adhere to, if a survey has not been performed yet.

David Ramkalawan

OPG

Yes

Yes

Michelle R. D'Antuono

Ingleside Cogeneration LP (Occidental Chemical Corporation)

No

Ingleside Cogeneration LP is generally supportive of the changes that the drafting team has made to PRC-005-2 and supporting documentation to address FERC Order 758. First and

foremost, we agree that the definition of “Protection System” should not be modified as it has implications to any standard that uses the term. This far exceeds the scope of FERC’s directive – which only identifies recloser maintenance as a reliability imperative. Second, we believe that the underlying technical basis for the identification of recloser relays that “can affect the reliability” of the BES is sound. The analysis performed by NERC’s System Analysis and Modeling and System Protection and Control Subcommittees (SAMS-SPCS) is compelling in our view. In this manner, the industry and CEAs can focus on those components which may pose risk to the local system – and not expend resources on those which do nothing to improve electric service delivery. However, as a Generator Owner, we are not sure how we will capture the information we need to conduct an analysis of our recloser relays. We can approach our Balancing Authority to have them provide the “capacity of the largest generating unit” within their control area – but have no recourse if they refuse to respond due to security or anti-competitive reasons. Even if this is not an issue, it seems plausible that an extended outage of the BA’s largest generator may re-set PRC-005-3’s applicability threshold downward. If this happens, we may be required to re-evaluate our equipment base on a moment’s notice. We don’t believe it is the drafting team’s intent to establish thresholds which may change in this manner. It would be far simpler if an Interconnect-wide capacity threshold could be established within PRC-005-3. Those Balancing Authorities that require a lower threshold could communicate their expectations to their base as they see fit.

Yes

Nazra Gladu

Manitoba Hydro

No

(1) Definition of Terms Used in Standard - statements in this section are contradictory. Please clarify if “When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.” or whether “The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.” Why are the following terms defined for use only within PRC-005-3 rather than being moved to the Glossary of Terms? (Automatic Reclosing, Unresolved Maintenance Issue, Segment, Component Type, Component and Countable Event). (2) Definitions of Terms Used in Standard, Protection System Maintenance Program (PSMP) (NERC Board of Trustees Approved Definition) - for clarity, the word ‘is’ in the following sentence, “...components is restored.” should be changed to “...components are restored.” Additionally, MH assumes that the words “NERC Board of Trustees Approved Definition” will be removed from the final version of the standard and that wording was provided for informational purposes only in the circulation of the standard. (3) Definitions of Terms Used in Standard, Automatic Reclosing - for clarity, we suggest beginning the definition with the following words ‘includes the following’. (4) Definitions of Terms Used in Standard, Segment - please clarify if the reference to Components in this definition is intended to be to the defined term “Components”? If so, the word should be capitalized at the end of this definition. If this is

not the intension, then an alternate word should be chosen to avoid confusion. (5) Definitions of Terms Used in Standard, Countable Event - the words "included in" from the last sentence of the definition are unnecessary and should be removed. (6) A. Introduction, 3. Purpose - for clarity, consider revising the purpose to read "To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) for maintaining functional operation". (7) 4.2.6 Automatic Reclosing - for section consistency, the words 'applied on BES Elements, including:' should be added to 4.2.6. Additionally, sections 4.2.6.1 and 4.2.6.2 should be rewritten as follows: 4.2.6.1 "Automatic Reclosing Applied on BES Elements at generating plant substations...." 4.2.6.2 "Automatic Reclosing Applied on BES Elements at substations...." (8) 4.2 footnote 1 - reference is made to equipment owner which is an undefined term. For clarity, consider referring to the Responsible Entity instead. In addition, some words seem to be missing which could provide some guidance as to what is being compared. For example, is it the intent of meaning - "does not result in a total loss of generation in the Interconnection exceeding the generation of the largest unit within the Balancing Authority Area..."? (9) 4.2.6.3 - the words 'integral part' are very subjective and may be difficult to assess. (10) 5. Effective Date - for completeness and consistency with other standards, text from the implementation plan should be moved to the standard Effective Date section. (11) 3. Measures - use the acronym for Protection System Maintenance Program, PSMP in M1 and M4 since this is not the first instance of this definition. (12) 1.3. Evidence Retention - use the acronym for Protection System Maintenance Program, PSMP in the third paragraph of this section because this is not the first instance of this definition. (13) PRC-005 - Attachment A, Criteria for a Performance-Based Protection System Maintenance Program - for completeness, add the acronym (PSMP) after the title. (14) Section D, Compliance, 1.1 - the paraphrased definition of 'Compliance Enforcement Authority' from the Rules of Procedure is not the standard language for this section. Is there a reason that the standard CEA language is not being used? (15) Section D, Compliance, 1.3 - this section was not updated to reference Automatic Reclosing. (16) Protection System Maintenance Program is defined in the standard as PMSP but then inconsistently referenced using both the full term and the acronym. (17) R1 - there are inconsistent references throughout the requirements made to 'Protection System and Automatic Closing Component Types' vs. 'Protection System Component Type and Automatic Reclosing Components' vs. 'Protection System and Automatic Reclosing Components'. Please clarify if this is the intent or consider correcting. (18) R2, R3 and R4 - there appears to be inconsistency in the drafting of R1, R2 and R3 as to what is required. There is no requirement to "implement and follow" a PMSP within the time based program the way there is for the performance based program. (19) R5 - MH believes that the requirement should be to make efforts, not demonstrate efforts. Demonstrating or providing evidence of the efforts would be the measure. (20) VSLs, R1 - the Requirement refers to both Protection System and Automatic Reclosing Components while the VSL refers only to Components. (21) VSLs, R2 - the wording of the VSL for this requirement does not seem consistent with the wording of Attachment A. (22) VSLs, R3 and R4 - rather than writing 'more than x% but y% or less', it would be clearer to write 'more than x% but less than y%'.

No

(23) General - use the acronyms for "Protection System Maintenance Program", PSMP and for

“Board of Trustees”, BOT. Both terms are referenced multiple times within the Implementation Plan document.

John Bee

exelon and its Affiliates

No

We understand the concerns related to reclosing relays however we do not agree that these devices should be included in PRC-005 because reclosing relays are not a protective device. The current system stability studies do not rely on automatic reclosing to maintain the reliability of the Bulk Power System.

No

1. 4.2.6.1 – How would a PRC-005-3 relay engineer determine or be made aware of “the capacity of the largest generating unit within the Balancing Authority Area” at any given moment in time? (e.g., suppose a large Nuclear unit that historically constituted the largest unit in a given BAA gets retired? This could present an unintentional compliance trap for the PRC-005-3 owner, unless this information is routinely updated and published as part of another NERC Standard, or by some other mechanism wherein the relay engineer could keep abreast of such changes in a timely manner). 2. 4.2.6.1 – More clarity is needed on exactly what is meant by “generating plant substations”, since this collective phrase is not defined in NERC’s most recent Glossary of Terms, dated 05apr13. BGE example: Wagner Unit #4 Sync Breaker is physically located at Wagner Power Plant, but because the step-up voltage is 230kV, the output feeds into Brandon Shores 230kV substation, rather than the local 110kV substation where the other Wagner machines feed into. In this case, would Brandon Shores be considered the “generating plant substation” for Wagner Unit #4? 3. 4.2.6.2 – The stated inclusion criteria “one bus away from generating plants specified in Section 4.2.6.1” introduces further interpretation difficulty when considering other common generating configurations, such as: 1. The sync breaker is on the low voltage side of the GSU transformer and the GSU high side leads constitute a “short” transmission line between the Plant (GO) and Substation (TO) 2. Same as above but the sync breaker is located on the high side of the GSU and connects to the TO switchyard by the “short” transmission line. 3. The sync breakers owned by the TO are located in the substation and connected to the high side of the GSU but operated by the GO, again at the other end of a short transmission line GO. (A legacy arrangement that results from the disintegration of formerly vertically integrated utilities) 4. Sync breaker on the high side of the GSU at the plant, but there is a “long” transmission line connecting the sync breaker to a TO substation.

David Jendras

Ameren

No

Ameren concurs with and also incorporates the SERC PCS comment regarding the interval for Automatic Reclosing exclusion studies by this reference. Ameren specific comments are: (1) We

request that the SDT add a FAQ: "Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?" Answer: "Yes, Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes its function from the Protection System. Automatic Reclosing is included in the PSMP because it is more concise than creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types." (2) We request that the SDT add a FAQ: "Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly. This practice verifies the Control circuitry associated with Automatic Reclosing including the close coil. Do you agree?" Answer: "Yes, since the breaker does successfully close in your practice. The intent of the Unmonitored Control circuitry Maintenance Activity is for the entity to functionally prove the Automatic Reclosing control path is intact through the breaker close coil." (3) We request that the SDT revise the Countable Event definition because as written it incorrectly implies that an Automatic Reclosing failure is a Misoperation. We believe that the Automatic Reclosing exclusion needs to be moved to a different sentence. (4) We request that the SDT add a FAQ: "Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain." Answer: "This test was chosen intentionally to err on the side of conservatism." (5) We request that the SDT augment the FAQ 2.4.1 to include "IEEE Device No. 79" in referring to the Automatic Reclosing relay because this helps clarify the scope.

Yes

PacifiCorp

Ryan Millard

PacifiCorp

Yes

Yes

Chris Mattson

Tacoma Power

Yes

Tacoma Power has the following comments regarding improvements to the standard: 1. *Regarding 4.2.6.1 and 4.2.6.2, there are some generating plants that may be in a different Balancing Authority area than the Transmission Owner with which they interconnect. This may complicate the determination of applicability of Automatic Reclosing under PRC-005-3. 2. Regarding 4.2.6.2, would it be necessary to maintain Automatic Reclosing components per

PRC-005-3 on BES Elements “facing” an applicable generating plant? For example, assume that a 5-circuit-mile long line connects Generating Plant A with Substation B. Would Automatic Reclosing components at Substation B on the connecting line need to be maintained per PRC-005-3? It seems unlikely that a failure of the Automatic Reclosing in this scenario would have adverse reliability impact to the BES. Of course, this assumes that there is not another generating plant within 10 circuit miles connected to Substation B. 3. Consider a substation located within 10 circuit miles of two or more generating plants, none of which individually applies under 4.2.6.1. Furthermore, assume that these generating plants collectively have a total installed generating plant capacity greater than the capacity of the largest generating unit within the Balancing Authority area? Would the substation apply to 4.2.6.2? 4. In 4.2.6.2, only Automatic Reclosing applied on BES Elements is applicable. What if there is a non-BES radial line connected to the substation? It seems that the reliability impact of improper Automatic Reclosing on this non-BES Element could be as high as that for improper Automatic Reclosing on a BES Element connected to the substation.

Yes

Kayleigh Wilkerson

Lincoln Electric System

No

LES is concerned with how components of a reclosing system would be identified if an automatic line isolation scheme is included within a reclosing scheme. For instance, in some configurations, if a trip were to occur on a transmission line, one reclose is performed. If the line immediately trips again (i.e., the fault is not cleared), the line is automatically isolated with a line switch followed by a second reclose. This is done in order to pick up the load on a transformer that may be on the same line terminal at the substation. However, in the event there is a failure of the line switch, the second reclose is cancelled. In consideration that this would affect reclosing, LES asks that the drafting team provide further clarification as to whether the components associated with the line switch operation would be included as part of the PSMP as well. Additionally, if reclosing is supervised by a sync-check function, whether included in the relay performing the reclosing or else in a separate relay, should that relay, and the voltage inputs needed to do sync-check, be included in the PSMP also? To ensure a consistent understanding amongst registered entities, LES recommends the drafting team add clarifying language to Applicability Section 4.2.6 or else provide further guidance within the Supplementary Reference and FAQ document.

Yes

Thomas Foltz

American Electric Power

No

It is not clear exactly which sort of automatic reclosing behavior(s) the proposed changes are attempting to prevent. Accidental reclosing? Failure to reclose? Providing clarity on this fundamental question will help industry in providing sound comments and feedback regarding PRC-005-3. Does mentioning “interlock circuits” in the second bullet under Automatic Reclosing (page 2 of redline) refer narrowly to circuitry inside breaker mechanisms or does it also include lockout strings associated with lockout relays?

No

We are concerned by the second bullet in the General Considerations section where it states “Whether each component has last been maintained according to PRC-005-2 (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof.” This section implies obligations which reference standards outside of PRC-005-3 and including a standard which is not yet fully approved (PRC-005-02), essentially serving as Measures outside of the proposed standard. In addition, obligations have no place in an implementation plan if they are not also specified within the standard itself. This overall approach sets a bad precedent for the standards development process. AEP does not recommend basing an implementation date on a standard which has not been fully approved, as that could prove problematic if in this case PRC-005-2 fails to become fully approved by FERC but PRC-005-3 *is* approved. Ideally, we recommend that the implementation date be solely based on PRC-005-3. However, should the drafting team still wish to include PRC-005-2 in the implementation plan, perhaps it could instead state that “Unimplemented Protection System Component maintenance activities per PRC-005-2 will continue to be implemented in accordance with the PRC-005-2 implementation plan. In addition, the following Automatic Reclosing Component maintenance activities will be implemented as part of PRC-005-3...”

Pepco Holdings Inc & Affiliates

David Thorne

Pepco Holdings Inc

No

We agree with the reasoning behind NERC’s System Analysis and Modeling Subcommittee (SAMS) recommendation to limit the applicability of automatic reclosing to only those installations that would impact the reliability of the BES. The three criteria (Sections 4.2.6.1, 4.6.2.2, and 4.6.2.3) identified in the PRC-005-3 draft and FAQ document seem reasonable and appropriate. However, additional clarification is needed to ensure uniform interpretation of these criteria. Consider the following scenario. Suppose a certain generating plant has 500 MVA of generation interconnected at a 230kV bus, 300 MVA interconnected at a 138kV bus, and 200 MVA interconnected at a 69kV bus. There are autotransformers connecting the 138kV bus to both the 230kV and 69kV busses. 1) How is total plant capacity to be calculated? Is it the sum of all generation capacity at the plant (500 + 300 + 200 = 1000 MVA), even though it is not all interconnected at the same bus, and some of it is connected below 100kV? Or, should the aggregate generation capacity interconnected on each bus be evaluated separately for those lines connected to that bus? Depending on the size of the autotransformers which interconnect the three busses, the transformer thru impedance could be comparable to, or

exceed, the equivalent impedance of 10 circuit miles of line. If this were the case, it would seem that evaluation of plant capacity should be permitted to be calculated on an individual bus basis, rather than a total plant basis. Also, can the 200 MVA of generation interconnected at the 69kV bus be excluded from the total plant capacity, since it is interconnected below 100kV, and therefore not BES generation? Section 4.2.6.1 should be re-worded to provide clarity and eliminate confusion on how to evaluate this plant capacity calculation. Also, specific examples illustrating how to apply this criterion would be helpful in the FAQ. 2) Section 4.2.6.1 states that it applies to “all BES elements at generating plant substations...”. The transmission line (including both ends) is considered a BES element. Therefore one might interpret this as applying to both ends of any BES element that terminates on a generating plant substation. We believe the intent of 4.2.6.1 is to only apply to the automatic reclosing schemes on the line terminals located at the generating station and to not apply to the automatic reclosing schemes on the opposite ends of the lines remote from the generating plant substation. Automatic reclosing schemes on lines terminating on generating stations usually employ a leader-follower philosophy, with the remote terminal programmed as the reclose initiate terminal, and the generating station end of the line reclosing only upon a successful restoration of the far end. A reclosing mal-function at the far terminal should have no consequences for the generating plant, provided there is no other electrically short (within 10 circuit miles) transmission path from the far terminal back to the generating plant. To provide clarity, Section 4.2.6.1 should be re-worded as follows: “Applied on the terminals of BES Elements located at generating plant substations...”. For consistency, Section 4.2.6.2 should also be re-worded as follows: “Applied on the terminals of BES Elements located at substations...”. Also, specific examples and clarifications in the FAQ would also be helpful. 3) For consistency, when determining plant capacity and capacity of the largest generating unit within the Balancing Authority Area, rated generator nameplate MVA ratings should be used rather than published seasonal MW values. 4) The NERC SAMS review concluded that automatic reclosing mal-performance affects BES reliability when “inadvertent reclosing near a generating station subjects the generation station to severe fault stresses”. The concern appears to be potential shaft torque damage, or instability, of rotating machines to automatic reclosing mal-performance. That being the case, generation sources that are not subject to severe fault stresses, such as inverter based generation, or static reactive sources (SVC’s, capacitor banks, etc.) should not be included in the calculation of total plant capacity. However, since synchronous condensers are subject to the same fault stresses as synchronous generators they should probably be included in the aggregate plant generation calculation, providing they are interconnected at 100kV, or above.

Yes

Brad Harris

CenterPoint Energy

No

The SAMS/SPCS study of automatic reclosing identifies 1 circuit-mile impedance as typically

adequate to prevent generating unit instability and that 10 circuit-miles impedance is a sufficient margin. CenterPoint Energy requests that the SDT reevaluate the technical basis for selecting 10 circuit-miles as “sufficient margin” and incorporating this distance into the Applicable Facilities section 4.2.6.2. Since the SAMS/SPCS study states that 1 circuit mile impedance is adequate, it is possible that 5 circuit-miles or some other distance will provide a sufficient margin.

Yes

SERC Protection and Controls Subcommittee

David Greene

SERC RRO

No

Under the Facilities Section, the drafting team included Footnote #1 which allows an exclusion of certain locations that meet the test criteria; however, there is no stated time frame to re-validate the results of stated test. We recommend that the drafting team specifies a re-validation period of 60 months.

Yes

Andrew Z. Pusztai

American Transmission Company

No

The PRC-005 standard is directed at the Transmission Owner (TO), not the Transmission Planner (TP). The TO may not have the ability to perform the analysis that is required to identify exclusions and ATC recommends that the SDT address this issue.

MRO NERC Standards Review Forum

Russ Mountjoy

MRO

Yes

The NSRF supports the draft standard PRC-005-3 addressing automatic reclosing as correct and appropriate.

Yes

Northeast Power Coordinating Council

Guy Zito

Northeast Power Coordinating Council

No

The maintenance for Automatic Reclosing installed on the lines defined at Section 4.2.1 should be done at the same time with the maintenance of Protection Systems installed on those lines. Similarly, the maintenance for Automatic Reclosing used as an integral part of a SPS defined in Section 4.2.4 should be done at the same time as the maintenance for a SPS. This should be reflected in this revision of the Standard. The Considerations for Maintenance and Testing of Autoreclosing Schemes report attached as a supporting document mentions as a credible failure “a close signal is issued with no delay or less delay than is intended”. This failure should be classified as either a normal contingency or an extreme contingency. The classification is important because the TPL standards define different study conditions based on contingency classifications. How are interconnections to be considered in Applicability Section 4.2.6 Automatic Reclosing? Section 4.2.6.1 states that Automatic Reclosing should be maintained “at generating plant substations where the total installed capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area”. However, depending on the assumptions used for system configurations, there may be other locations where if the double three phase fault described in Footnote 1 is applied, the total generation loss could be greater than the largest unit within the Balancing Authority. Also, should the criteria be based on largest single source loss rather than largest generating unit? Otherwise, there is no mechanism that triggers review of applicability of this standard. For example, what if the largest generating unit within the BA Area is removed permanently from service? This is applicable in the Northeast, where TO and GO functions are performed by different entities/owners. The BA is the entity that determines the largest single source loss in its area; they would also be the proper functional entity to identify the generator locations in 4.2.6.1. The TPL or the BAL standards could then include a trigger mechanism to review applicability of 4.2.6 to GOs and TOs for a change in the largest single source loss criteria/limit. From a Registration Criteria perspective, the terms “unit” and “plant” as employed in the Registration Criteria suggest a two-part Applicability test. The first part is a comparison between the single “largest generating unit” and a larger multi-unit generating plant located at a single site (i.e., the term a “plant” as used in NERC Rules of Procedure, Appendix 5B NERC Statement of Compliance Registry Criteria). In this first part of the test the sum of the capacity ratings of the smaller individual units exceeds the single “largest generating unit” within the Balancing Authority Area. This is compared with a single “largest generating unit.” The second part of the Applicability test relates to the “generating plant substations.” In this phrase the word “substations” is plural. This plural wording suggests that the multi-unit generating plant feeds more than one substation. Suggest the following alternatives to the wording of Section 4.2.6.1: “Where generating plant substations are interconnected locally at the generating plant site, or adjacent to the generating plant site, and applied on BES Elements at the generating plant substations.” Or “Automatic Reclosing is applicable where the total site installed generating plant capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area or when 4.2.6.3 applies.” Applicability Section 4.2.6.2 addresses the electrical and geographical proximity of the “generating plant substations” interconnections by stating “one bus away” and “less than 10 circuit-miles from the generating plant substation.” For

clarification, suggest revising Section 4.2.6.2 to read “Where generating plant substations are interconnected at a distance from the generating plant site, applied on BES Elements at substations located one bus away from generating plant substations when the substation is less than 10 circuit-miles from the generating plant substation.” What is the technical justification for the 10 circuit-miles? It may be necessary to confirm the 10 circuit miles with the Planning Coordinator. It is not clear if a substation “one bus away from generating plants” that meets the criteria in 4.2.6.2 and includes buses at two voltage levels, separated by a power transformer, is considered as one bus, or as two buses separated by a power transformer. If the former applies, reclosing relays on elements at only one of the substation buses would be included in this standard. If a reclosing relay is found non-functional during maintenance activity and has to be removed from service for an extended period of time, which in turn fully removes automatic reclosing functionality, is it still identified as an Unresolved Maintenance Issue? The final SAMS-SPCS report states that if “No close signal is issued under conditions that meet the intended design conditions, (...) this failure mode does not create any additional considerations for inclusion of autoreclosing relays in PRC-005”, which implies that it would not be identified as an Unresolved Maintenance Issue. Footnote 1 is not explicit as to the reclosing operation referred to. The Requirement appears to address only three pole, single shot reclosing. There is no reference to single pole reclosing or cases where multiple shot reclosing may be utilized. A more generalized statement should be considered: Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that, in the event of a close-in permanent fault, the reclosing utilized does not result in a total loss of generation in the Interconnection exceeding the largest unit within the Balancing Authority Area where the Automatic Reclosing is applied. Rationale should be provided to describe the system conditions to be considered for studying the three phase fault described in Footnote 1. Footnote 1 places the burden on the owner of the reclosing relays to demonstrate which reclosing relays can be excluded by making the determinations outlined in the footnote. This should be the role of the Reliability Coordinator or Planning Coordinator and not the equipment owner. Consequently, we believe that the applicability of this standard should be expanded to RCs and/or PCs in order to properly conduct the sort of studies asked for in the standard. Section 4.2.6.3 is not specific enough with regard to reclosing used in an SPS. The use of the word “integral part of an SPS” is subject to interpretation and may require details of the SPS that will not be readily available to the owner of the reclosing relays. There should be a process in place to update the list of the Automatic Reclosing excluded from being maintained. The standard must consider that neighboring entities may be involved in the lines being tested.

Yes

Hydro One Networks Inc.

Sasa Maljukan

Hydro One Networks Inc.

No

– We do not agree with Footnote 1 in the standard which places the onus on the equipment owner of the reclosing relays to demonstrate which reclosing relays can be excluded by making the determinations outlined in the footnote. This is clearly the role of the Reliability Coordinator or Planning Coordinator and not the equipment owner. Consequently, we believe that the applicability of this standard should be expanded to RCs and/or PCs in order to properly conduct the sort of studies asked for in the standard. – Also, the standard assumes that all relays are in scope and entities have to systematically exclude relays based on the footnote. We don't agree with this approach since it is onerous and leaves room for interpretations. We suggest that standard is changes so that the onus is placed on the RC or PC to identify such relays. – Section 4.2.6.3 is not specific enough in terms of in-scope reclosing used in an SPS. Use of the word “integral part of an SPS” is subject to interpretation and may require details of the SPS not readily available to the owner of the reclosing relays. – We propose that the maintenance for Automatic Reclosing installed on the lines defined at Section 4.2.1 should be done at the same time with the maintenance of Protection Systems installed on those lines. If the owner of the two relays is not the same, we recommend that the standard requires coordination between two entities. Similarly, the maintenance for Automatic Reclosing used as an integral part of a SPS defined in Section 4.2.4 should be done at the same time with the maintenance for SPS. The revision of the standard should only reflect these changes. Please see the rational below: The report attached as a supporting document mentions as a credible failure “a close signal is issued with no delay or less delay than is intended”. This failure should be classified as either a normal contingency or an extreme contingency. The classification is important because the TPL standards define different study conditions based on contingency classification. Sections 4.2.6.1 states that Automatic Reclosing should be maintained “at generating plants substations where the total installed capacity is greater than the capacity of the largest generating unit within the Balancing Authority”. However, depending on the assumptions (how the system is stressed, extreme weather, etc.) and specific configurations, there may be other locations, where if the double three phase fault described in the Footnote 1 is applied, the total generation loss could be greater than the largest unit within the Balancing Authorities. The standard lacks a common methodology for performing the double three phase fault described in the Footnote 1: – The standard does not specify the conditions (extreme weather base case, extreme contingencies base case, how the generators are dispatched, etc.) or what would be the time delay between the first and second fault. All these conditions may affect the total generation loss. – The 10 circuit-miles criteria should be confirmed with the Planning Coordinators. – Depending on the location of the line being tested, different neighboring entities may be involved. – There should be a process in place to update the list of the Automatic Reclosing excluded from being maintained.

Yes

Bill Fowler

City of Tallahassee

Yes
Anthony Jablonski
ReliabilityFirst
No
No, the reclosing relays in the Applicability section were overly restricted. Improper operation of reclosing relays can exacerbate fault conditions and severely damage equipment that affects the long term reliability of the Bulk Power System. The Applicability section limits the facilities concerning automatic reclosing to those integral to an SPS or substations (and those one bus away) where the total installed generating plant capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area. This bar is so high that substations with units as high as 1200 MVA may not be covered by this revised standard. The capacity limit should either be removed or reduced to no more than half the largest generating unit within a BA. Also, the definition of Automatic Reclosing should include supervisory elements like synchronism check or dead-line check as these can be integral parts of the reclosing scheme.
No
No, the implementation plan has an excessively long phased in approach that stretches out to 13 years after regulatory approval or 14 years after NERC Board of Trustees adoption
Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Marcus Pelt
Southern Company Operations Compliance
Yes
Under the Facilities Section, the drafting team included Footnote #1 which allows an exclusion of certain locations that meet the test criteria; however, there is no stated time frame to re-validate the results of stated test. We recommend that the drafting team specifies a re-validation period.
Yes
Cole Brodine
Nebraska Public Power District
No
*4.2.6.1 – Is the largest generator included or excluded? Based on the definition, the largest generator is not larger than the largest generator, so it would not be included. *Confirm other input to Automatic reclosing Relays are NOT included (including but not limited to...): Synch check relays. Voltage sensing devices Please explain or clarify better what the SPS includes,

specifically what does “integral part” mean? Please explain what a minimum trip-close-trip time delay is and how this exclusion would work. Please clarify which circuitry is applicable. An example would be A/B contacts, are these included or not?

No

To implement, it would cause us to have to verify that the reclose actually works as part of the functional trip check. Otherwise, we have the breakers and relays already classified as NERC.

PPL Corporation NERC Registered Affiliates

Nicholas A. Poluch

PPL Generation, LLC on behalf of its Supply NERC Registered Entities

No

1) There are currently two NERC approved projects filed at FERC (PRC-005-1.1b and PRC-005-2). NERC should consider waiting to proceed with this project until the current projects are ruled on and FERC provides further direction. 2) For 4.2.6, for reclosing capability, it is unclear what functionality is to be tested. Please define. 3) For PRC-005-3 section 4.2.6.2, please provide the technical basis for this application of the Standard. Specifically, this application states for Automatic Reclosing: “Applied on 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.” Please provide the technical basis/reasoning for the 10-mile criteria. At a recent North American Transmission Forum Workshop on Protection System Maintenance Program it was implied that the 10 mile rule is for cases where a generator has a short connection to another company’s substation. Please clarify if this is the case. 4) For PRC-005-3 section R1, consider adding the following language that is used for PRC-005-1.1b “each Generator Owner that owns a generation or generator interconnection Facility Protection System...” This is NERC-approved language that has been through the standards development process and has technical justification through Project 2010-07. 5) Please provide the technical basis for R1.1 which requires battery testing for DC Supply Component Type Protection Systems to be time based. 6) Table 1-2 of PRC-005-3 requires functional testing of non-monitored communication systems on a 4 month cycle. Please specify NERC’s criteria for the functional testing (what attributes to be tested). Additionally, specifically define monitoring criteria and data intervals for continuous monitoring of communications systems (to see if check back (fail/no fail) monitoring is adequate).

Yes

Oliver Burke

Entergy Services, Inc.

Yes

Entergy agrees with the inclusion of the reclosing relay maintenance requirement except for how the terminology is addressed. Entergy suggests not adding of the term Automatic Reclosing; instead add reclosing relay and the associated circuitry description under Protection

System definition.
Yes
Entergy agrees with the addition of table 4 except for the terminology Automatic Reclosing.
ISO RTO Council Standards Review Committee
Greg Campoli
NYISO
No
<p>The IRC members compliment the SDT in using the recommendations provided in the SAMS/SPCS Order 758 Autoreclosing Report for the applicability of this standard directive to specific reclosing relays. By using these recommendations, Transmission Owners are provided guidance and reduced burden that should satisfy the Commission conclusion in the Order that “specific requirements fo selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System.” The IRC members are not directly impacted by the PRC-005 requirements from a compliance standpoint because we are generally not Transmission Owners. We are raising these questions to highlight the lack of communications between the stakeholder industry experts and the regulator directing technical requirements on the industry . As everyone in the industry knows, seven years’ experience with the ERO has caused significant burdens on meeting compliance requirements with numerous requirements being in effect and entities having to significantly increase resources in compliance and not always justifying whether such expenses are a benefit to the end consumer. NERC must develop processes and form relationships with the regulators who have these specific technical concerns to bring their concerns and issues to the industry experts in a more direct and efficient manner to avoid delays in standards development and approval and expending more resources in the regulatory process rather through a technical process. We question whether the approach the SDT has taken to address the FERC Directive in Order 758 addresses the core reliability concern that the Order seems to raise. First, the Order states that reclosing relays are not explicitly identified as part of the “Protection System” and if it plays a part in the “Protection System” to “achieve or meet system performance requirements” or “can exacerbate fault conditions when not properly maintained and coordinated” then there could be a gap in the maintenance and testing of the relays. Second the Order recognizes that certain parties in comments to the NOPR believe reclosing relays are used not for reliability reasons but for business purposes in restoration post-contingency. Further commenters stated that specific call outs for reclosing relays in PRC-005 are not necessary because reclosing relays are already integral to an entity’s relay maintenance program. Nevertheless, FERC has directed NERC to add reclosing relays to the standard There is no further technical justification for adding reclosing relays to the standards. The referenced language from the Order can be challenged by a protection system designer in that a reclosing relay may not be integral to “achieve or meet system performance requirements” nor “can exacerbate fault conditions” because they may have been designed to provide onlyrestoration of service for customer satisfaction and be in a part of the system that cannot exacerbate a fault condition (e.g. tap configuration). Does a registered entity subject to this requirement have the ability to</p>

demonstrate a particular reclosing relay does not meet the apparent reliability concern specified in the Order and exclude those reclosing relays from the compliance program? An all inclusive approach to apply the PRC-005 requirements for all reclosing relays may have little to no reliability benefit to the grid. In addition, we offer the following comments for the SDT's consideration to achieve consistency in the terms used and the precise devices that the revised standard should apply: a. Definition of PSMP: the term "Automatic Reclosing" should not be capitalized since it is indicated that the term is defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms. With this term not to be balloted and included in the Glossary, it should be in lower case. b. Order 758 directed NERC to include "reclosing relays" that can affect the reliable operation of the Bulk-Power System. Automatic reclosing is an act or intent, not a device. It is the latter that needs to be maintained and tested for continued functionality, not the former. Therefore, we suggest that the term "Automatic Reclosing" be replaced with "reclosing devices" or "reclosing relays" in the revised PSMP definition, in Sections A.1, A.3 and A.4.2.6, and throughout the standard where "automatic reclosing" is addressed/referenced. c. We interpret the FERC directive to require not just the automatic reclosing devices/relays be included in PRC-005, but also the relays/devices that may be used for manual reclosing. In other words, both automatic and manual reclosing devices/relays need to be included in the standard. To enable this applicability, we suggest not removing the word "automatic" where it appears.

Yes

We agree with the proposed implementation plan, but suggest that the term "Automatic Reclosing" with "reclosing devices" or "reclosing relays" be applied throughout the Implementation Plan document (see out comments under Q1, above).

Duke Energy

Colby Bellville

Duke Energy

No

We believe the modifications to the PRC-005-2 Applicability section 4.2.6.1 should recognize that the reliability issue is inadvertent reclosing, and therefore applicability on BES Elements at generating plant substations should be limited to the timing and sync check functions of reclosing. There is no need to include all DC circuitry, etc. because if a problem existed aside from timing and sync check, it would just prevent reclosing. Also, rather than being focused only on plant capacity, there should be some recognition that plant location on the BES is also a consideration. Duke Energy believes the Applicability section 4.2.6.2 should be based on a technical assessment as illustrated in the SAMS/SPCS paper. This type of assessment should be based on a simulation of a close-in-three-phase fault for twice the normal clearing time. This simulation would capture a minimum trip-close time delay.

Yes

Kevin Luke

Georgia Transmission Organization
Agree
Michael Falvo
Independent Electricity System Operator
No
<p>Comments: We only agree with the scope presented in the SAR. We do not agree with the proposed changes, as stated below. We suggest that the maintenance for Automatic Reclosing installed on the lines defined at Section 4.2.1 could be done at the same time with the maintenance of Protection Systems installed on those lines. Similarly, the maintenance for Automatic Reclosing used as an integral part of a SPS defined in Section 4.2.4 could be done at the same time with the maintenance for SPS. Please see the rational below. The report attached as a supporting document mentions as a credible failure “a close signal is issued with no delay or less delay than is intended”. This failure should be classified as either a normal contingency or an extreme contingency, to be consistent with the TPL standards contingency classification. Section 4.2.6.1 states that Automatic Reclosing should be maintained “at generating plants substations where the total installed capacity is greater than the capacity of the largest generating unit within the Balancing Authority”. However, depending on the assumptions (how the system is stressed, extreme weather, etc.) and specific configurations, there may be other locations, where if the sequential three phase fault described in the Footnote 1 is applied, the total generation loss could be greater than the largest unit within the Balancing Authorities. The standard lacks a common methodology for testing sequential three phase faults described in the Footnote 1:</p> <ul style="list-style-type: none"> o The standard does not specify the conditions (extreme weather base case, extreme contingencies base case, how the generators are dispatched, etc.) or what would be the time delay between the first and second fault. All these conditions may affect the total generation loss. o The 10 circuit-miles criteria should be confirmed with the Planning Coordinators. o Depending on the location of the line being tested, different neighboring entities may be involved. o There should be a process in place to update the list of the Automatic Reclosing excluded from being maintained.
Yes
FirstEnergy
Larry Raczkowski
FirstEnergy Corp
No
<p>1. FE supports the technical aspects and requirements of the standard. 2. FE is questioning the accuracy of the red-lining in this document. Many of the definitions were reflected as “new” when in fact only minor changes were made. 3. FE also questions why the drafting team is proposing deletions in the Revision History of the standard. Complete and accurate revision</p>

history is information that needs to be retained for future reference.
Yes
FE agrees with the proposed Implementation Plan for V3.
Florida Municipal Power Agency
Frank Gaffney
Florida Municipal Power Agency
No
FMPA is generally supportive of the changes to the standard to accommodate Reclosing Relays as directed by FERC. We have one comment: The SDT should recognize that there are a number of small BAs and that the Applicability 4.2.6.1 would be better stated as the largest generator within the Reliability Coordinator area as opposed to the largest generator in the Balancing Authority area (e.g., for some BAs, the largest generator in their area is less than 10 MW and not even registered). If left unchanged, FMPA would recommend a Negative vote.
Yes
Jonathan Meyer
Idaho Power Company
Yes
Yes
ACES Standards Collaborators
Jason Marshall
ACES
No
(1) While we believe the standard should not be modified until FERC rules on version 2 of PRC-005, we appreciate that the drafting team adopted the recommendations of the Planning Committee in limiting the applicable reclosing relays to only those that may impact reliability. Limiting applicability to only those auto-reclosing relays that are close to large generating stations or that are applied as part of an SPS appears to fully meet the intent of the FERC directive. This limited applicability will help avoid the negative reliability impacts that would occur as a result of expanding applicability. If all auto-reclosing relays were included, the standard would detract resources away from reliability needs to unnecessary documentation. (2) We have a concern with the "Auto Reclosing" definition being proposed in this draft standard. Some parts of the definition may require further clarification and may be vague. What does "such as anti-pump and 'various' interlock circuits" mean? Will auditors and industry subject matter experts understand them in the same way? "Various" is not a clear

adjective to describe interlock circuits. We recommend revising the entire definition to clearly state the scope of the devices (possibly even the IEEE numbers). (3) There are concerns with the supplementary reference document because it assumes that PRC-005-2 will be approved by the Commission. This assumption is presumptuous and should not reflect any Commission rulings that have yet to occur. We recommend stating the current status of the PRC-005-2 project, which was filed with FERC in February 2013 and is pending the Commission's approval. Statements such as "PRC-005-2 'replaced' PRC-011" should be modified to "PRC-005-2 will replace PRC-011 upon approval from FERC," or something similar. (4) We suggest additional clarification may be needed for section 4.2.6.1 regarding applicability of auto-reclosing relays. This section states that the standard will apply to auto-reclosing relays implemented at the generating plant substation where installed generating plant capacity is greater than the largest generating unit in the BA. We presume this was selected because the largest generating unit is often the most severe single contingency and establishes the amount of contingency reserves that must be carried. If our assumption is correct, we would suggest that the applicability may need to be based on the largest resource in a Reserve Sharing Group (RSG) or BA. There is at least one large BA in the Eastern Interconnection where the largest resource is actually the loss of a 500-kV line that triggers a generation runback scheme. If a BA participates in an RSG, the BA would have access to contingency reserves that would be carried by the group and, thus, the only time a call for contingency reserves would exceed the amount carried would be when the generation loss is greater than the largest resource in the RSG.

No

(1) The SDT needs to clarify the implementation plan. The document is confusing because it focuses on the PRC-005-2 standard, which is not yet FERC-approved. As a result, this implementation plan is a moving target. Why not wait until PRC-005-2 gets approved before initiating another project for the same standard? This would reduce some of the timing issues and confusion. (2) Why is the drafting team revising a standard that has not been approved by the Commission yet? The second version was only filed in February 2013, and the timing of this project is premature. It is quite possible that the Commission could remand or direct revisions to parts of the standard and issue other directives associated with the version 2, which would then need to be addressed. This project is untimely and should be postponed until there is a final order from FERC. At that point, there may be justification to continue with this project, expand the scope of the SAR to address any new directives that may be included in a final order of PRC-005-2, or to determine that a guidance document is an appropriate way to satisfy the FERC orders. (3) Again, the drafting team needs to consider other methods of answering FERC directives. Not every directive needs to be addressed by developing or revising a standard. Adding reclosing relays to PRC-005 only complicates the most-violated non-CIP standard. There is enough concern about this standard already and the drafting team should consider alternative means to address the reclosing relay issue besides a standard revision. (4) This project contains similar timing issues as CIP version 4 and CIP version 5 because it is being developed prior to FERC issuing a final order on the previous version of the standard. The timing is problematic; registered entities will be forced to constantly be focusing on the next standard. The implementation plan should provide additional time, similar to PRC-005-2's two intervals, to allow registered entities enough time to adjust their PSMT programs for Protection

Systems, and then have additional time to adjust their PSMT plan and implement auto-reclosing relays. (5) Thank you for the opportunity to comment.

Scott Langston

City of Tallahassee

Yes

Bonneville Power Administration

Jamison Dye

Transmission Reliability Program

Yes

Yes

Consideration of Comments

Project 2007-17.2 Protection System Maintenance and Testing – Phase 2 (Reclosing Relays)

The Project 2007-17.2 Drafting Team thanks all commenters who submitted comments on the Standard Authorization Request (SAR) for Protection System Maintenance and Testing (Reclosing Relays). The SAR was posted for a 30-day formal comment period from April 5, 2013 through May 6, 2013. Stakeholders were asked to provide feedback on the SAR and associated documents through a special electronic comment form. There were 24 sets of comments, including comments from approximately 93 different people from approximately 64 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's [project page](#).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.¹

Summary Consideration of all Comments Received

SAR

The SAR was previously posted for information only along with the third draft of PRC-005-2 in May, 2012. The Standards Process Manual supports posting of a SAR for a comment period at the same time that a draft of the resulting standard is posted for a formal comment period. "For SARs that are limited to addressing regulatory directives, or revisions to Reliability Standards that have had some vetting in the industry, authorize posting the SAR for a 30-day informal comment period with no requirement to provide a formal response to the comments received."

Commenters agreed that the scope of this SAR addresses the regulatory directive associated with Order 758 while a few commenters suggested that NERC pursue "equally efficient and effective" methods for achieving the reliability intent of the FERC directive regarding the maintenance of

¹ The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

reclosing relays. The drafting team noted that “equally efficient and effective” alternatives were proposed to FERC in the NOPR preceding Order 758, and they were rejected.

No regional variances were identified as being necessary because of this project.

Two commenters noted they may need to modify or establish business practices.

The drafting team removed the parenthetical and revised a sentence of the SAR’s “Need” statement because the SAMS and SPCS could not identify an application in which autoreclosing is used in coordination with a protection system to meet the system performance requirements in a NERC Reliability Standard or in establishing an IROL. The sentence was formerly read: “Modifying the standard in this fashion will impact Bulk Electric System (BES) reliability by assuring that the reclosing relays (installed to meet performance goals of approved NERC Standards) are properly maintained so that they may be expected to perform properly.” It now reads: “Modifying the standard in this fashion will assure that those reclosing relays that can affect the reliability of the Bulk Electric System are properly maintained.”

Index to Questions, Comments, and Responses

1. Do you agree that the scope of this SAR addresses the regulatory directive associated with FERC Order No. 758? If not, please explain..... 9

2. Are you aware of any regional variances that will be needed as a result of this project? If yes, please identify the regional variance.15

3. Are you aware of any business practice that will be needed or that will need to be modified as a result of this project? If yes, please identify the business practice.18

4. If you have any other comments on this SAR that you haven't already mentioned, please provide them here:21

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	Louis Slade	Dominion	X		X		X	X				
Additional Member		Additional Organization	Region	Segment Selection									
1.	Connie Lowe	NERC Compliance Policy	NA - Not Applicable	1, 3, 5, 6									
2.	Chip Humphrey	Fossil & Hydro	NPCC	5									
3.	Sean Iseminger	Fossil & Hydro	RFC	5									
4.	Jeff Bailey	Nuclear	NA - Not Applicable	5									
5.	Mike Garton	NERC Compliance Policy		1, 3, 5, 6									
6.	Michael Crowley	Electric Transmission Compliance	SERC	1, 3									
7.	Randi Heise	NERC Compliance Policy		1, 3, 5, 6									
8.	Matt Woodzell	Fossil & Hydro	SERC	5									
2.	Group	Colby Bellville	Duke Energy	X		X		X	X				

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
Additional Member Additional Organization Region Segment Selection														
1.	Doug Hils	RFC	1											
2.	Lee Schuster	FRCC	3											
3.	Dale Goodwine	SERC	5											
4.	Greg Cecil	RFC	6											
3.	Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X					
Additional Member Additional Organization Region Segment Selection														
1.	William Smith	FurstEnergy Corp	RFC	1										
2.	Cindy Stewart	FirstEnergy Corp	RFC	3										
3.	Doug Hohlbaugh	Ohio Edison	RFC	4										
4.	Ken Dresner	FirstEnergy Solutions	RFC	5										
5.	Kevin Querry	FirstEnergy Solutions	RFC	6										
4.	Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X								
Additional Member Additional Organization Region Segment Selection														
1.	Carlton Bradshaw	Delmarva Power & Light Co	RFC	1, 3										
2.	Carl Kinsley	Delmarva Power & Light Co	RFC	1, 3										
5.	Group	Robert Rhodes	SPP Standards Review Group		X									
Additional Member Additional Organization Region Segment Selection														
1.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5										
2.	Timothy Bobb	Westar Energy	SPP	1, 3, 5, 6										
3.	Afshin Jalilzadeh	Westar Energy	SPP	1, 3, 5, 6										
4.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6										
5.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6										
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6										
7.	Russ Matzke	Westar Energy	SPP	1, 3, 5, 6										
6.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X					
Additional Member Additional Organization Region Segment Selection														
1.	Rusty Hardison	SERC	1											
2.	Ryland Revelle	SERC	1											
3.	Karen Ryland	SERC	1											

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
7.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X					
Additional Member		Additional Organization	Region	Segment	Selection									
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4										
2.	Jim Howard	Lakeland Electric	FRCC	3										
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3										
4.	Lynne Mila	City of Clewiston	FRCC	3										
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4										
6.	Randy Hahn	Ocala Utility Services	FRCC	3										
8.	Group	Jason Marshall	ACES Standards Collaborators						X					
Additional Member		Additional Organization	Region	Segment	Selection									
1.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5										
2.	Tom Alban	Buckeye Power	RFC	3, 4										
3.	Kevin Lyons	Central Iowa Power Cooperative	MRO											
4.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1										
5.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5										
6.	John Shaver	Southwest Transmission Cooperative	WECC	1										
7.	Scott Brame	NCEMC	SERC	1, 3, 4, 5										
9.	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.	Carmen Agavrioloai	Independent Electricity System Operator	NPCC	2										
3.	Greg Campoli	New York Independent System Operator	NPCC	2										
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1										
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1										
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10										
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5										
8.	Kathleen Goodman	ISO - New England	NPCC	2										
9.	Michael Jones	National Grid	NPCC	1										
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1										
11.	Christina Koncz	PSEG Power LLC	NPCC	5										
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
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. Brian Shanahan	National Grid	NPCC												
21. Wayne Sipperly	New York Power Authority	NPCC 5												
22. Donald Weaver	New Brunswick System Operator	NPCC 2												
23. Ben Wu	Orange and Rockland Utilities	NPCC 1												
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3												
10. Group	Jamison Dye	Bonneville Power Administration	X		X		X	X						
Additional Member	Additional Organization	Region	Segment Selection											
1. Heather Laslo	SPC Technical Svcs	WECC	1											
2. Jason Burt	PSC Technical Svcs	WECC	1											
3. Brenda Vasbinder	Work Planning and Evaluation	WECC	1											
11. Individual	Ryan Millard	PacifiCorp	X		X		X	X						
12. Individual	Marcus Pelt	Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X						
13. Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X						
14. Individual	John Bee	Exelon and its Affiliates	X		X		X							
15. Individual	Bill Fowler	City of Tallahassee			X									
16. Individual	Chris Mattson	Tacoma Power	X		X	X	X	X						
17. Individual	Thomas Foltz	American Electric Power	X		X		X	X						
18. Individual	Brad Harris	CenterPoint Energy	X											

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Individual	Kenn Backholm	Public Utility District No.1 of Snohomish County	X		X	X	X	X			X	
20.	Individual	Andrew Z. Puztai	American Transmission Company	X									
21.	Individual	Anthony Jablonski	ReliabilityFirst										X
22.	Individual	Kevin Luke	Georgia Transmission Corporation	X									
23.	Individual	Jonathan Meyer	Idaho Power Company	X									
24.	Individual	Scott Langston	City of Tallahassee	X									

1. Do you agree that the scope of this SAR addresses the regulatory directive associated with FERC Order No. 758? If not, please explain.

Summary Consideration:

Commenters agreed that the scope of this SAR addresses the regulatory directive associated with Order 758. No changes made to the SAR as a result of comments from Question 1.

Some comments pertained to the standard rather than the SAR; however, the drafting team responded to all individual comments.

Several commenters were concerned about initiating the project to establish PRC-005-3 before PRC-005-2 is FERC approved. The drafting team explained that they are acting in accordance with the schedule provide to FERC in an informational filing submitted by NERC, in response to FERC Order 758 which stated: “By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.” In the Order, FERC accepted NERC’s commitment to address the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System within the standards development process. Phase 2 (Reclosing Relays) of Project 2007-17 Protection System Maintenance and Testing was initiated to develop PRC-005-3 and satisfy NERC’s commitment to the FERC.

Several commenters questioned the scope of reclosing relays that might be included in the standard; the drafting team explained that the SAR provides the boundaries (scope) for the proposed standard action, establishing the general framework for the project.

Several commenters proposed that NERC pursue “equally efficient and effective” methods for achieving the reliability intent of the FERC directive regarding the maintenance of reclosing relays. The drafting team noted that “equally efficient and effective” alternatives were proposed to FERC in the NOPR preceding Order 758, and they were rejected.

Several commenters objected to the provision within the SAR that optionally permitted changes to the definition of “Protection System”. The drafting team explained that this represented one option for the drafting team to consider, and noted that the drafting team decided not to pursue that option.

Organization	Yes or No	Question 1 Comment
American Electric Power	No	1. AEP supports the efforts of the drafting team, but is concerned by pursuing a version 3 of this standard before the second version has been approved by

Organization	Yes or No	Question 1 Comment
		<p>FERC. There is significant content within version 3 that was new to version 2, so proper implementation of version 3 would rely on the eventual approval of version 2 in its entirety. The content of version 3 has apparently been drafted with this in mind, however, it over-complicates the implementation plan of version 3 by basing it in-part on the previous and not-yet-approved version, and leaving it vulnerable in the event version 2 does not pass.</p> <p>2. In addition, it is not clear exactly which sort of automatic reclosing behavior(s) the proposed changes are attempting to prevent. Accidental reclosing? Failure to reclose? Providing clarity on this fundamental question will help industry in providing sound comments and feedback regarding PRC-005-3.</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> The drafting team thanks you for your support. The drafting team is acting in accordance with the schedule NERC provided to FERC, which outlines the timeframes by which NERC will respond, through the standards drafting process, to the directives of FERC Order 758. Specifically regarding reclose relays (Footnote 37), FERC directed NERC to: “By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.” The SAR is general, in that it specifies that requirements for maintenance and testing of reclosing relays be established, and that “The Applicability section of the Standard must be modified to describe explicitly those devices that entities are to maintain in accordance with the revised standard.” Further, the SAR notes that the drafting team use the report prepared by the NERC SPCS and SAMS as an aid in preparing PRC-005-3; this report includes a discussion regarding the automatic reclosing behavior(s) to be addressed, as well as recommendations regarding the specific applicability. 		
ReliabilityFirst	No	<p>No, the scope of the SAR only lists three bullet items. It should as a minimum include a lead in sentence similar to the following: PRC-005-2 has been revised to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk Power System. The bullet items do not include the changes made to the Definitions of Terms, Requirements or Compliance sections.</p>

Organization	Yes or No	Question 1 Comment
<p>Response: Thank you for your comments. The discussion that you suggest is included in the “Detailed Description” portion of the SAR.</p>		
<p>Dominion</p>	<p>No</p>	<p>The SAR goes beyond the directive in that it appears to indicate that all reclosing relays must operate properly in order to maintain BES reliability. The fact is that, in a majority of applications, these relays exist primarily to decrease outage times. The SAR should be limited to only those reclosing relays whose failure to operate correctly could adversely impact reliable operation of the BES. Dominion therefore recommends revising the sentence that reads “The Applicability section of the Standard must be modified to describe explicitly those devices that entities are to maintain in accordance with the revised standard.” To read “The Applicability section of the Standard must be modified to describe explicitly those reclosing relays that entities are to maintain in accordance with the revised standard.”</p>
<p>Response: Thank you for your comments.</p> <p>The SAR drafting team agrees that many reclosing relays are installed to facilitate automated restoration, and not to specifically maintain BES reliability. The SAR therefore states: “The Standard Drafting Team shall modify NERC Standard PRC-005-2 to explicitly address the maintenance and testing of reclosing relays <u>which can affect the reliable operation of the Bulk Electric System.</u>” <i>[Emphasis added]</i> When drafting the SAR, consideration was given to concerns that automatic reclosing maintenance may extend to more than simply the reclosing relays themselves.</p>		
<p>ACES Standards Collaborators</p>	<p>Yes</p>	<ol style="list-style-type: none"> 1. While we agree the SAR addresses the regulatory directive, we question the value of modifying this standard further when the newest version has yet to be approved. If FERC issues significant directives, the directives could ultimately impact the direction that drafting team should take with modifying the standard to include reclosing relays. Furthermore, because PRC-005 is historically one of the most violated standards primarily because of the zero-defect approach to compliance, we question the value of adding another relay type to the list of relays subject to zero-defect compliance. We are concerned there will be another step function in potential violations that do not ultimately

Organization	Yes or No	Question 1 Comment
		<p>support reliability but detract from reliability because they are focused on documentation.</p> <p>2. We believe that there are other equally-effective options to address the FERC directives, such as issuing an industry guidance document. If the standard ultimately needs to be modified, a guidance document could allow the drafting team to wait until FERC rules on the PRC-005 to determine if there will be any impacts on adding reclosing relays to the standard.</p>
<p>Response: Thank you for your comments.</p> <p>1. The drafting team thanks you for your support. The drafting team is acting in accordance with the schedule NERC provided to FERC, which outlines the timeframes by which NERC will respond, through the standards drafting process, to the directives of FERC Order 758. Specifically regarding reclose relays (Footnote 37), FERC directed NERC to: “By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.”</p> <p>2. NERC, as well as other entities, provided comments in response to FERC NOPR discussions regarding requirements related to maintenance of automatic reclosing, essentially proposing equally effective options. FERC, in response, directed that NERC specifically include requirements related to maintenance of automatic reclosing within PRC-005.</p>		
Duke Energy	Yes	<p>However we are concerned that the SAR includes possible revision of the definition of Protection System. We don’t believe attempting to revise that definition is necessary or advisable.</p>
<p>Response: Thank you for your comments.</p> <p>The SAR does provide the drafting team the option to revise the definition of Protection System. The drafting team chose not to modify the definition.</p>		
FirstEnergy	Yes	
Pepco Holdings Inc & Affiliates	Yes	

Organization	Yes or No	Question 1 Comment
SPP Standards Review Group	Yes	
Florida Municipal Power Agency	Yes	
Northeast Power Coordinating Council	Yes	
Bonneville Power Administration	Yes	
PacifiCorp	Yes	
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Manitoba Hydro	Yes	
Exelon and its Affiliates	Yes	
City of Tallahassee	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 1 Comment
Public Utility District No.1 of Snohomish County	Yes	
American Transmission Company	Yes	
Idaho Power Company	Yes	
City of Tallahassee	Yes	

2. Are you aware of any regional variances that will be needed as a result of this project? If yes, please identify the regional variance.

Summary Consideration: Commenters did not identify any regional variances that would be needed.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	AEP is not aware of any regional variances that would be needed as a result of this project.
Dominion	No	
Duke Energy	No	
FirstEnergy	No	
Pepco Holdings Inc & Affiliates	No	
SPP Standards Review Group	No	
Florida Municipal Power Agency	No	
ACES Standards Collaborators	No	
Bonneville Power Administration	No	

Organization	Yes or No	Question 2 Comment
PacifiCorp	No	
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
Manitoba Hydro	No	
Exelon and its Affiliates	No	
City of Tallahassee	No	
Tacoma Power	No	
Public Utility District No.1 of Snohomish County	No	
American Transmission Company	No	
ReliabilityFirst	No	
Idaho Power Company	No	

Organization	Yes or No	Question 2 Comment
City of Tallahassee	No	

3. Are you aware of any business practice that will be needed or that will need to be modified as a result of this project? If yes, please identify the business practice.

Summary Consideration: Two commenters noted they may need to modify or establish their business practices. No changes made to the SAR.

Organization	Yes or No	Question 3 Comment
Dominion	No	
Duke Energy	No	
FirstEnergy	No	
Pepco Holdings Inc & Affiliates	No	
SPP Standards Review Group	No	
ACES Standards Collaborators	No	
Bonneville Power Administration	No	
PacifiCorp	No	
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation;	No	

Organization	Yes or No	Question 3 Comment
Southern Company Generation and Energy Marketing		
Manitoba Hydro	No	
City of Tallahassee	No	
Tacoma Power	No	
Public Utility District No.1 of Snohomish County	No	
American Transmission Company	No	
ReliabilityFirst	No	
Idaho Power Company	No	
City of Tallahassee	No	
American Electric Power	Yes	AEP believes that it is likely that some of its business practices would need to at least be modified as a result of this project
Response: Thank you for your comment.		
CenterPoint Energy	Yes	Business practices will be needed to: 1. Document and monitor the generating plant capacity at all Company owned generation interconnection facilities 2. Document and monitor the largest generating unit located in the Balancing Authority 3. Document and monitor the Company owned stations meeting the Applicability attributes described in 4.2.6 of PRC-005-3.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments.		
Florida Municipal Power Agency	Yes	
Exelon and its Affiliates	Yes	

4. If you have any other comments on this SAR that you haven't already mentioned, please provide them here:

Summary Consideration:

The comments were general in nature. Some comments were repeats from Question 1 while others pertained to the standard rather than the SAR. However, the drafting team responded to all individual comments.

In response to a comment, the drafting team revised a sentence in the SAR's "Need" statement from "Modifying the standard in this fashion will impact Bulk Electric System (BES) reliability by assuring that the reclosing relays (installed to meet performance goals of approved NERC Standards) are properly maintained so that they may be expected to perform properly." to "Modifying the standard in this fashion will assure that those reclosing relays that can affect the reliability of the Bulk Electric System are properly maintained."

Organization	Question 4 Comment
<p>ACES Standards Collaborators</p>	<p>(1) We understand that NERC is obligated by law to address all FERC directives issued to them. However, not all FERC directives require the development or revision of a reliability standard. FERC has been clear that other alternatives may be used as long as they are equally effective and efficient. NERC and the drafting team need to consider other alternatives that would produce an equally effective method of ensuring that auto-reclosing relays will be maintained and tested. The drafting team should consider a survey of all registered entities subject to the current PRC-005 standard to see if they include auto-reclosers in their PSMT program. This issue goes back to compliance - whether the entity needs to maintain documentation for each of these devices. A guidance document may be an appropriate solution to handle this FERC directive.(2) Thank you for the opportunity to comment.</p>
<p>Response: Thank you for your comments.</p> <p>NERC, as well as other entities, provided comments in response to FERC NOPR discussions regarding requirements related to maintenance of automatic reclosing, essentially proposing equally effective options. FERC, in response, directed that NERC specifically include requirements related to maintenance of automatic reclosing within PRC-005.</p>	

Organization	Question 4 Comment
Manitoba Hydro	(1) Brief Description of Proposed Standard Modifications/Actions - for completeness, add '(BES)' after Bulk Electric System. (2) Need - capitalize 'misoperation' because it appears in the Glossary of Terms. (3) Need - remove the words "Bulk Electric System" to leave only the acronym, BES because this is the second instance of BES in the document.
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. The SAR drafting team is not required to use acronyms for multiple appearances of terms. The SAR drafting team elected to spell out "Bulk Electric System" wherever it appears. 2. The term, "misoperation" is used in a general context within the SAR, rather than the specific context addressed by the NERC definition. 3. The SAR drafting team is not required to use acronyms for multiple appearances of terms. The SAR drafting team elected to spell out "Bulk Electric System" wherever it appears. 	
Tennessee Valley Authority	1. Are reclosing relays considered "protective relays"?2. Are reclosing relays considered part of the "protective system"?3. Is Table 1-3 applicable to CCVTs that feed only reclosing relays?4. Does a "reclosing relay" include all relays used to perform all type of automatic reclosing actions, i.e. sync check, dead line, dead bus, and blind reclosing?
<p>Response: Thank you for your comments.</p> <p>Comments 1-4: All of these considerations are left to the standard drafting team to address.</p>	
ReliabilityFirst	Can the SDT clarify whether high-speed automatic reclosing is covered within the scope of the SAR?
<p>Response: Thank you for your comments.</p> <p>Yes, high-speed reclosing is covered within the scope of the SAR and left to the consideration of the standard drafting team.</p>	
FirstEnergy	FE supports the referenced SAR as stated.

Organization	Question 4 Comment
<p>Response: Thank you for your comment.</p>	
<p>Dominion</p>	<p>Having reviewed, and generally agree with, the technical study performed jointly by the NERC System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) and subsequently approved by the NERC Planning Committee. We therefore support the OPTIONAL approach shown near the bottom of the SAR as we believe would revise the standard in a way that applies new requirements only to those elements of the protection system where reclosing is applied it been demonstrated to that an adverse impact on the BES could occur if those element(s) are not included in one or more reliability standard requirements.</p>
<p>Response: Thank you for your comments.</p>	
<p>Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing</p>	<ol style="list-style-type: none"> 1. It seems out of order to be posting a draft SAR for informal comment at the same time that the revised standard which is the topic of the SAR is posted for a formal comment period. 2. Further, FERC has not approved PRC-005-2 yet. Any changes required by FERC would affect the draft of PRC-005-3. The proposed standard modification seems premature given that PRC-005-3 SAR is still in draft that PRC-005-2 is not yet approved.
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. The SAR was previously posted for information only along with the third draft of PRC-005-2 in May, 2012. The Standards Process Manual supports posting of a SAR for a comment period at the same time that a draft of the resulting standard is posted for a formal comment period. “For SARs that are limited to addressing regulatory directives, or revisions to Reliability Standards that have had some vetting in the industry, authorize posting the SAR for a 30-day informal comment period with no requirement to provide a formal response to the comments received.” 2. The drafting team is acting in accordance with the schedule NERC provided to FERC, which outlines the timeframes by which NERC will respond, through the standards drafting process, to the directives of FERC Order 758. Specifically regarding 	

Organization	Question 4 Comment
<p>reclose relays (Footnote 37), FERC directed NERC to: “By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.”</p>	
SPP Standards Review Group	None
City of Tallahassee	None
City of Tallahassee	None
CenterPoint Energy	<p>Page 2, Paragraph 2 of the “Need” section of the SAR includes a parenthetical “(installed to meet performance goals of approved NERC Standards)”. Recommend deleting this parenthetical statement as the SAMS/SPCS paper concluded on page 2 that “SAMS and SPCS have not identified an application in which auto reclosing is used in coordination with a protection system to meet the system performance requirements in a NERC Reliability Standard or in establishing an IROL”.</p>
<p>Response: Thank you for your comments. The drafting team revised the language to read as follows: “Modifying the standard in this fashion will assure that those reclosing relays that can affect the reliability of the BES are properly maintained.”</p>	
Public Utility District No.1 of Snohomish County	<p>The Public Utility District No.1 of Snohomish County has reviewed and supports this Standard Authorization Request and concluded that the revisions and modifications do not seem impractical or technically unreasonable.</p>
<p>Response: Thank you for your comments.</p>	
Duke Energy	<p>The SAR includes statements under “Goals” and “Detailed Description” that the defined term Protection System might be revised as part of this project. Those statements should be removed from the SAR. We strongly believe that the issue of maintenance and testing of any reclosing relays which can affect reliable operation of the BES, can be addressed without attempting to modify the definition of Protection System.</p>

Organization	Question 4 Comment
	<p data-bbox="155 300 705 331">Response: Thank you for your comments.</p> <p data-bbox="155 354 1848 423">The SAR does provide the drafting team the option to revise the definition of Protection System. The drafting team chose not to modify the definition.</p>

END OF REPORT

Consideration of Comments

Project 2007-17.2 Protection System Maintenance and Testing – Phase 2 (Reclosing Relays) PRC-005-3

The Project 2007-17.2 Drafting Team thanks all commenters who submitted comments on the PRC-005-3 standard for Protection System Maintenance and Testing (Reclosing Relays). The standard was posted for a 30-day formal comment period from April 5, 2013 through May 6, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 36 sets of comments, including comments from approximately 143 different people from approximately 95 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's [project page](#).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.¹

Summary Consideration of all Comments Received

Definitions

Protection System Maintenance Program (PSMP):

Un-capitalized the term “Automatic Reclosing”

Automatic Reclosing

Minor revisions to provide clarity, the definition now reads:

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Segment

Capitalized the defined term “Component”

¹ The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Countable Event

Updated to incorporate reference to new Tables 4-1 through 4-2, and added the term “Protection System” as a modifier of Misoperation for clarity.

Applicability

To add clarity, the drafting team revised 4.2.6 Facilities and each of the sections: 4.2.6.1, 4.2.6.2. and 4.2.6.3. The associated footnote was modified for congruence with the referenced sections.

Requirements

The Table reference in Requirement R1, Part 1.2 was updated to include Tables 4-1 through 4-2, and the wording was revised for clarity.

The Table reference in Requirement R3 was updated to include Tables 4-1 through 4-2.

Measures:

The Table reference in Measure M1 was updated to include Tables 4-1 through 4-2.

Evidence Retention

The drafting team added the phrase “or Automatic Reclosing” for clarity.

VSLs

The Table references in the VSLs were updated to include Tables 4-1 through 4-2.

Version History

The previous version history of PRC-005 was added for completeness.

Tables

The Tables were updated to accommodate the addition of Tables 4-1 through 4-2.

Attachment A

Attachment A was updated to include Tables 4-1 through 4-2.

Supplementary Reference and FAQ

Additional content was added to reflect changes in the standard.

Additional Implementation Plan

A second Implementation Plan was developed to address generation changes in the Balancing Authority Area that result in additional locations becoming subject to the Applicability of PRC-005-3. The document titled: “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area”, is posted with the draft standard.

Unresolved Minority Views

- Several commenters suggested making general changes to PRC-005-2. The drafting team responded that the SAR precludes the drafting team from making general revisions to the standard in content or arrangement, only allowing modifications to explicitly address the maintenance and testing of reclosing relays which can affect the reliable operation of the Bulk Electric System. The drafting team did not make any of the suggested changes.

- Several commenters were concerned about initiating the project to establish PRC-005-3 before PRC-005-2 is FERC approved. The drafting team explained that they are acting in accordance with the schedule provide to FERC in an informational filing submitted by NERC, in response to FERC Order 758 which stated: “By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.” In the Order, FERC accepted NERC’s commitment to address the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System within the standards development process. Phase 2 (Reclosing Relays) of Project 2007-17 Protection System Maintenance and Testing was initiated to develop PRC-005-3 and satisfy NERC’s commitment to the FERC.

- A few commenters questioned the complexity of the Implementation Plan for PRC-005-3 which includes the Protection System aspects of PRC-005-2 and adds the new aspects of Automatic Reclosing from PRC-005-3. The plan addresses the implementation of the PRC-005-2 requirements based on the approval date of PRC-005-2 and adds the implementation of the revised requirements that include Automatic Reclosing based on the approval date of PRC-005-3. This approach provides clarity regarding the implementation dates for maintenance of Protection System and Automatic Reclosing Components. The drafting team crafted the Implementation Plan with guidance from NERC legal staff and believes the Implementation Plan is clear once carefully reviewed.

Index to Questions, Comments, and Responses

1. The drafting team modified PRC-005-2 and its associated Supplementary Reference and FAQ document to address Automatic Reclosing as directed in FERC Order No. 758. Do you agree with these changes? If not, please provide specific suggestions for improvement..... 12

- 2. The drafting team developed an Implementation Plan for PRC-005-3 based on the Implementation Plan for PRC-005-2 to address the addition of Automatic Reclosing. Do you agree with the implementation plan regarding Automatic Reclosing? If not, please provide specific suggestions for improvement.....45

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
Additional Member Additional Organization Region Segment Selection														
1.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5										
2.	Timothy Bobb	Westar Energy	SPP	1, 3, 5, 6										
3.	Afshin Jalilzadeh	Westar Energy	SPP	1, 3, 5, 6										
4.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6										
5.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6										
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6										
7.	Russ Matzke	Westar Energy	SPP	1, 3, 5, 6										
3.	Group	David Thorne	Pepco Holdings Inc & Affiliates		X		X							
Additional Member Additional Organization Region Segment Selection														
1.	Carl Kinsley	Delmarva Power & Light Co	RFC	1										
2.	Carlton Bradshaw	Delmarva Power & Light Co	RFC	1, 3										
4.	Group	David Greene	SERC Protection and Controls Subcommittee											
Additional Member Additional Organization Region Segment Selection														
1.	Paul Nauert	Ameren	SERC											
2.	John Miller	GTC	SERC											
3.	Phil Winston	Southern Company	SERC											
4.	Bridget Coffman	Santee Cooper	SERC											
5.	Steve Edwards	Dominion VP	SERC											
6.	Charlie Fink	Entergy	SERC											
7.	Joel Masters	SCE&G	SERC											
8.	Jay Farrington	PowerSouth	SERC											
9.	David Fountain	Duke Energy	SERC											
10.	Flavio Graciaa	Southern Company	SERC											
11.	Jerry Blackley	Duke Energy	SERC											
12.	David Greene	SERC RRO	SERC											
5.	Group	Russ Mountjoy	MRO NERC Standards Review Forum		X	X	X	X	X	X				X
Additional Member Additional Organization Region Segment Selection														
1.	Alice Ireland	Xcel	MRO	1, 3, 5, 6										
2.	Chuck Lawrence	ATC	MRO	1										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment												
			1	2	3	4	5	6	7	8	9	10			
3. Dan Inman	MPC	MRO	1, 3, 5, 6												
4. Dave Rudolph	BEPC	MRO	1, 3, 5, 6												
5. Kayleigh Wilkerson	LES	MRO	1, 3, 5, 6												
6. Jodi Jensen	WAPA	MRO	1, 6												
7. Joseph DePoorter	MGE	MRO	3, 4, 5, 6												
8. Ken Goldsmith	ALTW	MRO	4												
9. Lee Kittleson	OTP	MRO	1, 3, 5												
10. Mahmood Safi	OPPD	MRO	1, 3, 5, 6												
11. Marie Knox	MISO	MRO	2												
12. Mike Brytowski	GRE	MRO	1, 3, 5, 6												
13. Scott Bos	MPW	MRO	1, 3, 5, 6												
14. Scott Nickels	RPU	MRO	4												
15. Terry Harbour	MEC	MRO	1, 3, 5, 6												
16. Tom Breene	WPS	MRO	3, 4, 5, 6												
17. Tony Eddleman	NPPD	MRO	1, 3, 5												
6. Group	Guy Zito	Northeast Power Coordinating Council													X
Additional Member		Additional Organization	Region	Segment Selection											
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10											
2.	Carmen Agavrioloai	Independent Electricity System Operator	NPCC	2											
3.	Greg Campoli	New York Independent System Operator	NPCC	2											
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1											
5.	Chris De Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1											
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10											
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5											
8.	Kathleen Goodman	ISO - New England	NPCC	2											
9.	Michael Jones	National Grid	NPCC	1											
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1											
11.	Christina Koncz	PSEG Power LLC	NPCC	5											
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9											
13.	Bruce Metruck	New York Power Authority	NPCC	6											
14.	Si-Truc Phan	HydroQuebec TransEnergie	NPCC	1											
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5											

Group/Individual	Commenter	Organization	Registered Ballot Body Segment												
			1	2	3	4	5	6	7	8	9	10			
16. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10												
17. Robert Pellegrini	The United Illuminating Company	NPCC	1												
18. David Ramkalawan	Ontario Power Generation, Inc.		5												
19. Brian Robinson	Utility Services	NPCC	8												
20. Brian Shanahan	National Grid	NPCC	1												
21. Don Weaver	New Brunswick System Operator	NPCC	2												
22. Wayne Sipperly	New York Power Authority	NPCC	5												
23. Ben Wu	Orange and Rockland Utilities	NPCC	1												
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3												
7.	Group	Sasa Maljukan	Hydro One Networks Inc.	X											
Additional Member Additional Organization Region Segment Selection															
1.	David Kiguel	Hydro One Networks Inc.	NPCC	1											
2.	Paul Difilippo	Hydro One Networks Inc.	NPCC	1											
8.	Group	Nicholas A. Poluch	PPL Corporation NERC Registered Affiliates	X		X		X	X						
Additional Member Additional Organization Region Segment Selection															
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1											
2.	Karl B. Ingebrigtsen	LG&E and KU Services Company	SERC	3											
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5											
4.			WECC	5											
5.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6											
6.			NPCC	6											
7.			SERC	6											
8.			SPP	6											
9.			RFC	6											
10.			WECC	6											
11.				6											
9.	Group	Greg Campoli	ISO RTO Council Standards Review Committee		X										
Additional Member Additional Organization Region Segment Selection															
1.	Steve Myers	ERCOT	ERCOT	2											

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																	
			1	2	3	4	5	6	7	8	9	10								
2. Ben Li	IESO	NPCC	2																	
3. Matt Goldberg	ISONE	NPCC	2																	
4. Bill Phillips	MISO	MRO	2																	
5. Tom Bowe	PJM	RFC	2																	
6. Charles Yeung	SPP	SPP	2																	
10. Group	Colby Bellville	Duke Energy		X		X		X	X											
Additional Member	Additional Organization	Region	Segment Selection																	
1. Doug Hils		RFC	1																	
2. Lee Schuster		FRCC	3																	
3. Dale Goodwine		SERC	5																	
4. Greg Cecil		RFC	6																	
11. Group	Larry Raczkowski	FirstEnergy		X		X	X	X	X											
Additional Member	Additional Organization	Region	Segment Selection																	
1. William Smith	FirstEnergy Corp	RFC	1																	
2. Cindy Stewart	FirstEnergy Corp	RFC	3																	
3. Doug Hohlbaugh	Ohio Edison	RFC	4																	
4. Ken Dresner	FirstEnergy Solutions	RFC	5																	
5. Kevin Querry	FirstEnergy Solutions	RFC	6																	
12. Group	Frank Gaffney	Florida Municipal Power Agency		X		X	X	X	X											
Additional Member	Additional Organization	Region	Segment Selection																	
1. Tim Beyrle	City of New Smyrna Beach	FRCC	4																	
2. Jim Howard	Lakeland Electric	FRCC	3																	
3. Greg Woessner	Kissimmee Utility Authority	FRCC	3																	
4. Lynne Mila	City of Clewiston	FRCC	3																	
5. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4																	
6. Randy Hahn	Ocala Utility Services	FRCC	3																	
13. Group	Jason Marshall	ACES Standards Collaborators							X											
Additional Member	Additional Organization	Region	Segment Selection																	
1. Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5																	
2. Tom Alban	Buckeye Power	RFC	3, 4																	
3. Kevin Lyons	Central Iowa Power Cooperative	MRO																		

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																	
			1	2	3	4	5	6	7	8	9	10								
4. Megan Wagner	Sunflower Electric Power Corporation	SPP	1																	
5. John Shaver	Arizona Electric Power Cooperative	WECC	4, 5																	
6. John Shaver	Southwest Transmission Cooperative	WECC	1																	
7. Scott Brame	NCEMC	SERC	1, 3, 4, 5																	
14. Group	Jamison Dye	Bonneville Power Administration		X		X		X	X											
Additional Member	Additional Organization	Region	Segment Selection																	
1. Heather Laslo	SPC Technical Svcs	WECC	1																	
2. Jason Burt	PSC Technical Svcs	WECC	1																	
3. Brenda Vasbinder	Work Planning and Evaluation	WECC	1																	
15. Individual	Ryan Millard	PacifiCorp		X		X		X	X											
16. Individual	Marcus Pelt	Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		X		X		X	X											
17. Individual	Doug Jensen	Vandolah Power Company						X												
18. Individual	Herb Schrayshuen	Self																	X	
19. Individual	David Ramkalawan	OPG						X												
20. Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP (Occidental Chemical Corporation)						X												
21. Individual	Nazra Gladu	Manitoba Hydro		X		X		X	X											
22. Individual	John Bee	exelon and its Affiliates		X		X		X												
23. Individual	David Jendras	Ameren		X		X		X	X											
24. Individual	Chris Mattson	Tacoma Power		X		X	X	X	X											
25. Individual	Kayleigh Wilkerson	Lincoln Electric System		X		X		X	X											
26. Individual	Thomas Foltz	American Electric Power		X		X		X	X											
27. Individual	Brad Harris	CenterPoint Energy		X																

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
28.	Individual	Andrew Z. Puztai	American Transmission Company	X										
29.	Individual	Bill Fowler	City of Tallahassee			X								
30.	Individual	Anthony Jablonski	ReliabilityFirst											X
31.	Individual	Cole Brodine	Nebraska Public Power District	X		X		X						
32.	Individual	Oliver Burke	Entergy Services, Inc.	X		X		X	X					
33.	Individual	Kevin Luke	Georgia Transmission Organization	X										
34.	Individual	Michael Falvo	Independent Electricity System Operator		X									
35.	Individual	Jonathan Meyer	Idaho Power Company	X										
36.	Individual	Scott Langston	City of Tallahassee	X										

1. The drafting team modified PRC-005-2 and its associated Supplementary Reference and FAQ document to address Automatic Reclosing as directed in FERC Order No. 758. Do you agree with these changes? If not, please provide specific suggestions for improvement.

Summary Consideration:

Numerous commenters agreed with the proposed changes.

Several commenters had concerns regarding the definition of Automatic Reclosing. The drafting team revised the definition to read: "Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay."

Several commenters suggested making general changes to PRC-005-2. The drafting team responded that the SAR precludes the drafting team from making general revisions to the standard in content or arrangement, only allowing modifications to explicitly address the maintenance and testing of reclosing relays which can affect the reliable operation of the Bulk Electric System. The drafting team did not make any of the suggested changes.

Several commenters requested the Applicability sections pertaining to Automatic Reclosing be revised for better specificity. The drafting team responded by revising each of the sections 4.2.6.1, 4.2.6.2, and 4.2.6.3. The drafting team revised Applicability 4.2.6.1 to specify that the relevant "Automatic Reclosing is applied on the terminals of Elements connected to the BES bus located..." and 4.2.6.2 to specify that the "Automatic Reclosing is applied on the terminals of all BES Elements" for more clarity. The drafting team also revised 4.2.6.1 and the footnote to specify that 'gross' capacity should be used both for individual units and for plants. Furthermore, the drafting team revised sections 4.2.6.1 and the footnote to clarify that the applicable locations are where "the largest BES generating unit within the Balancing Authority Area..." Applicability 4.2.6.3 now reads: "Automatic Reclosing applied as an integral part of an SPS specified in Section 4.2.4."

Several commenters had questions regarding the meaning of "trip-close-trip" in the Applicability footnote. The drafting team explained that this addresses conditions where a failure in the Automatic Reclosing results in an immediate close of the breaker followed by an immediate trip, following the initial fault. The drafting team noted that the affected TO, GO, and DP would be responsible for performing the evaluation described in the footnote if they desire to exclude otherwise-applicable facilities.

Several commenters were concerned about initiating the project to establish PRC-005-3 before PRC-005-2 is FERC approved. The drafting team explained that they are acting in accordance with the schedule provide to FERC in an informational filing submitted by NERC, in response to FERC Order 758 which stated: “By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.” In the Order, FERC accepted NERC’s commitment to address the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System within the standards development process. Phase 2 (Reclosing Relays) of Project 2007-17 Protection System Maintenance and Testing was initiated to develop PRC-005-3 and satisfy NERC’s commitment to the FERC.

Several commenters had concerns related to applicable facilities changing because of generation changes within the Balancing Authority Area. The drafting team developed a second implementation plan: “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area”, to alleviate these concerns.

A number of commenters questioned how they would be aware of the largest generator in the Balancing Authority Area. The drafting team explained that the Balancing Authority would have this information and would be able to provide it to them.

Updates were made and additional content was added to the Supplementary Reference and FAQ document to reflect changes in the standard.

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	No	(1) Definition of Terms Used in Standard - statements in this section are contradictory. Please clarify if “When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.” or whether “The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.” Why are the following terms defined for use only within PRC-005-3 rather than being moved to the Glossary of Terms? (Automatic Reclosing, Unresolved Maintenance Issue, Segment, Component Type, Component and Countable Event). (2) Definitions of Terms Used in Standard, Protection System Maintenance Program (PSMP) (NERC Board of Trustees Approved Definition) - for clarity, the word ‘is’ in the following sentence, “...components is restored.” should be changed to “...components are restored.”

Organization	Yes or No	Question 1 Comment
		<p>Additionally, MH assumes that the words “NERC Board of Trustees Approved Definition” will be removed from the final version of the standard and that wording was provided for informational purposes only in the circulation of the standard. (3) Definitions of Terms Used in Standard, Automatic Reclosing - for clarity, we suggest beginning the definition with the following words ‘includes the following’. (4) Definitions of Terms Used in Standard, Segment - please clarify if the reference to Components in this definition is intended to be to the defined term “Components”? If so, the word should be capitalized at the end of this definition. If this is not the intension, then an alternate word should be chosen to avoid confusion. (5) Definitions of Terms Used in Standard, Countable Event - the words “included in” from the last sentence of the definition are unnecessary and should be removed. (6) A. Introduction, 3. Purpose - for clarity, consider revising the purpose to read “To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) for maintaining functional operation”. (7) 4.2.6 Automatic Reclosing - for section consistency, the words ‘applied on BES Elements, including:’ should be added to 4.2.6. Additionally, sections 4.2.6.1 and 4.2.6.2 should be rewritten as follows: 4.2.6.1 “Automatic Reclosing Applied on BES Elements at generating plant substations....”4.2.6.2 “Automatic Reclosing Applied on BES Elements at substations....” (8) 4.2 footnote 1 - reference is made to equipment owner which is an undefined term. For clarity, consider referring to the Responsible Entity instead. In addition, some words seem to be missing which could provide some guidance as to what is being compared. For example, is it the intent of meaning - “does not result in a total loss of generation in the Interconnection exceeding the generation of the largest unit within the Balancing Authority Area...”? (9) 4.2.6.3 - the words ‘integral part’ are very subjective and may be difficult to assess. (10) 5. Effective Date - for completeness and consistency with other standards, text from the implementation plan should be moved to the standard Effective Date section. (11) 3. Measures - use the acronym for Protection System Maintenance Program, PSMP in M1 and M4 since this is not the first instance of this definition. (12) 1.3. Evidence Retention - use the acronym for Protection System Maintenance Program, PSMP in the third paragraph of this section</p>

Organization	Yes or No	Question 1 Comment
		<p>because this is not the first instance of this definition. (13) PRC-005 - Attachment A, Criteria for a Performance-Based Protection System Maintenance Program - for completeness, add the acronym (PSMP) after the title. (14) Section D, Compliance, 1.1 - the paraphrased definition of 'Compliance Enforcement Authority' from the Rules of Procedure is not the standard language for this section. Is there a reason that the standard CEA language is not being used? (15) Section D, Compliance, 1.3 - this section was not updated to reference Automatic Reclosing. (16) Protection System Maintenance Program is defined in the standard as PMSP but then inconsistently referenced using both the full term and the acronym. (17) R1 - there are inconsistent references throughout the requirements made to 'Protection System and Automatic Closing Component Types' vs. 'Protection System Component Type and Automatic Reclosing Components' vs. 'Protection System and Automatic Reclosing Components'. Please clarify if this is the intent or consider correcting. (18) R2, R3 and R4 - there appears to be inconsistency in the drafting of R1, R2 and R3 as to what is required. There is no requirement to "implement and follow" a PMSP within the time based program the way there is for the performance based program. (19) R5 - MH believes that the requirement should be to make efforts, not demonstrate efforts. Demonstrating or providing evidence of the efforts would be the measure. (20) VSLs, R1 - the Requirement refers to both Protection System and Automatic Reclosing Components while the VSL refers only to Components. (21) VSLs, R2 - the wording of the VSL for this requirement does not seem consistent with the wording of Attachment A. (22) VSLs, R3 and R4 - rather than writing 'more than x% but y% or less', it would be clearer to write 'more than x% but less than y%'.</p>
<p>Response: Thank you for your comment.</p> <ol style="list-style-type: none"> <li data-bbox="205 1268 1858 1453"> <p>(a) The first statement originally referred to both the revised definition of Protection System and the term Protection System Maintenance Program (PSMP). When FERC approved the Protection System definition revision, the drafting team removed that term from this section, but failed to change the plural reference to singular. This has now been corrected in the standard.</p> <p>(b) Terms included in the NERC Glossary of Terms carry their definition regardless of the standard in which they are used.</p> 		

Organization	Yes or No	Question 1 Comment
		<p>The drafting team believes the definitions of the terms slated to remain with PRC-005 would not be appropriate for use in other standards.</p> <ol style="list-style-type: none"> 2. (a) The use of “is restored” is correct. The reference is “proper operation... is restored”, not that components are restored. (b) The original definition of PSMP will be removed from PRC-005-2 following FERC approval; the revised definition of PSMP (adding Automatic Reclosing) will be removed from PRC-005-3 when that standard is FERC approved. The references to ‘NERC Board of Trustees Approved Definition’ will be removed from the standards upon FERC approval. 3. The drafting team revised the standard to address your comment by adding “Includes the following Components:”. 4. The drafting team corrected the non-capitalized term. 5. The drafting team agrees with your suggestion but is precluded by the scope of the SAR for this project to make general content changes. 6. The drafting team is precluded by the scope of the SAR for this project to make general content changes. 7. The drafting team revised the standard in consideration of your comment. 8. Responsible Entity is not a defined term and ‘equipment owner’ is self explanatory, therefore, the drafting team did not make the suggested change. In response to your other comment, the drafting team revised the footnote to provide more clarity. 9. The drafting team believes the use of “integral part” (in·te·gral: essential to completeness – Merriam-Webster) within the context of 4.2.6.3 clearly conveys the standard would apply to Automatic Reclosing used as an integral part of a Special Protection System. 10. The drafting team believes that entities need to consider the Implementation Plan in its entirety rather than simply knowing the Effective Date for PRC-005-3. 11. The use of acronyms is optional. The drafting team chose not to in the instances cited. 12. The use of acronyms is optional. The drafting team chose not to in the instances cited. 13. The use of acronyms is optional. The drafting team chose not to in the instances cited. 14. This is the boiler plate CEA language currently used in all reliability standards. 15. Thank you. The drafting team made the revision to the standard. 16. The use of acronyms is optional. The drafting team chose not to in the instances cited. 17. The drafting team reviewed the use of the terms and made changes as needed. 18. Requirement R3 establishes that entities with components addressed by a time-based PSMP must maintain those components “in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4”. Requirement (R3) effectively constitutes “implementing and

Organization	Yes or No	Question 1 Comment
<p>following” the PSMP.</p> <p>19. The drafting team is precluded by the scope of the SAR for this project to make general content changes.</p> <p>20. The drafting team revised Requirement R1 such that the VSL for Requirement R1 is now consistent with the requirement.</p> <p>21. The drafting team believes the language of the VSL for R2 is correctly composed and consistent with the criteria for a Performance-Based Maintenance Program provided in Attachment A.</p> <p>22. The drafting team is precluded by the scope of the SAR for this project to make general content changes. Furthermore, your suggested change would leave a gap in the phased VSL approach.</p>		
<p>ACES Standards Collaborators</p>	<p>No</p>	<p>(1) While we believe the standard should not be modified until FERC rules on version 2 of PRC-005, we appreciate that the drafting team adopted the recommendations of the Planning Committee in limiting the applicable reclosing relays to only those that may impact reliability. Limiting applicability to only those auto-reclosing relays that are close to large generating stations or that are applied as part of an SPS appears to fully meet the intent of the FERC directive. This limited applicability will help avoid the negative reliability impacts that would occur as a result of expanding applicability. If all auto-reclosing relays were included, the standard would detract resources away from reliability needs to unnecessary documentation. (2) We have a concern with the “Auto Reclosing” definition being proposed in this draft standard. Some parts of the definition may require further clarification and may be vague. What does “such as anti-pump and ‘various’ interlock circuits” mean? Will auditors and industry subject matter experts understand them in the same way? “Various” is not a clear adjective to describe interlock circuits. We recommend revising the entire definition to clearly state the scope of the devices (possibly even the IEEE numbers).(3) There are concerns with the supplementary reference document because it assumes that PRC-005-2 will be approved by the Commission. This assumption is presumptuous and should not reflect any Commission rulings that have yet to occur. We recommend stating the current status of the PRC-005-2 project, which was filed with FERC in February 2013 and is pending the Commission’s approval. Statements such as “PRC-005-2 ‘replaced’ PRC-011” should be modified to “PRC-005-2 will replace PRC-011 upon approval from FERC,” or something similar. (4) We suggest additional clarification may be needed for section 4.2.6.1 regarding applicability of auto-reclosing relays. This section states that</p>

Organization	Yes or No	Question 1 Comment
		<p>the standard will apply to auto-reclosing relays implemented at the generating plant substation where installed generating plant capacity is greater than the largest generating unit in the BA. We presume this was selected because the largest generating unit is often the most severe single contingency and establishes the amount of contingency reserves that must be carried. If our assumption is correct, we would suggest that the applicability may need to be based on the largest resource in a Reserve Sharing Group (RSG) or BA. There is at least one large BA in the Eastern Interconnection where the largest resource is actually the loss of a 500-kV line that triggers a generation runback scheme. If a BA participates in an RSG, the BA would have access to contingency reserves that would be carried by the group and, thus, the only time a call for contingency reserves would exceed the amount carried would be when the generation loss is greater than the largest resource in the RSG.</p>
<p>Response: Thank you for your comment.</p> <ol style="list-style-type: none"> 1. The drafting team thanks you for your support. The drafting team is acting in accordance with the schedule NERC provided to FERC, which outlines the timeframes by which NERC will respond, through the standards drafting process, to the directives of FERC Order 758. Specifically regarding reclosing relays (Footnote 37), FERC directed NERC to: “By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.” Providing the schedule for addressing both reclosing relays and relays that do not respond to electrical quantities addressed this requirement of FERC Order 758. 2. The drafting team removed the exclusionary language from the definition of Automatic Reclosing and added discussion to the Supplementary Reference and FAQ document. 3. The Supplementary Reference and FAQ document provided with this posting is for PRC-005-3. Therefore, this document will only be relevant when PRC-005-3 is approved by FERC. The drafting team has updated the Introduction and Summary section of the PRC-005-3 Supplementary Reference and FAQ document to provide a summary of Order 758 that are driving the revisions to PRC-005-2. 4. The language in the Applicability section of the draft standard reflects the recommendations provided in the SPCS-SAMS Order 758 Autoreclosing Report. The technical authors (SPCS and SAMS) considered alternative language before making the final recommendation. 		

Organization	Yes or No	Question 1 Comment
Nebraska Public Power District	No	<p>*4.2.6.1 - Is the largest generator included or excluded? Based on the definition, the largest generator is not larger than the largest generator, so it would not be included.*Confirm other input to Automatic reclosing Relays are NOT included (including but not limited to...):Synch check relays.Voltage sensing devicesPlease explain or clarify better what the SPS includes, specifically what does “integral part” mean?Please explain what a minimum trip-close-trip time delay is and how this exclusion would work.Please clarify which circuitry is applicable. An example would be A/B contacts, are these included or not?</p>

Response: Thank you for your comment.

1. Generators are neither included nor excluded by Applicability section 4.2.6.1., as PRC-005-3 applies to Protection System and Automatic Reclosing equipment, not the lines or generators themselves. This section specifically refers to Automatic Reclosing equipment 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 [individual] generating unit within the Balancing Authority Area. The largest single generator is excluded if it is the only generator at the plant because the system is planned and operated to withstand the loss of that generator.
2. The definition of Automatic Reclosing provided in PRC-005-3 refers to specific components of automatic reclosing (reclose relays and control circuitry). By definition, therefore, any component not included in the definition, such as the examples you provided (synch check relays and voltage sensing devices) would not be considered components of Automatic Reclosing.
3. Automatic reclosing components that are an “integral part” of a Special Protection System (SPS) would be Automatic Reclosing that is necessary for the SPS to function properly and provide the outcome intended. If failure or inadvertent operation of Automatic Reclosing keeps an SPS from performing its intended function, the requirements of PRC-005-3 would apply to that equipment.
4. Trip-close-trip includes the time it takes from initiation of the trip signal through the initiation of a reclose signal and subsequent breaker trip (the Fault is still there after the initial trip). This includes the time it takes for the breaker contacts to open (trip time), plus the time it takes for the breaker to close back in (reclose time) and immediately trip out again to clear the fault (second trip time). The entity would need to evaluate if twice the normal clearing time is less than the critical clearing time for the generator.
5. The standard requires verification that Automatic Reclosing, upon initiation, does not issue a premature closing command.

Organization	Yes or No	Question 1 Comment
Specific activities have been added to Table 4 regarding close control circuitry associated with an SPS.		
PPL Corporation NERC Registered Affiliates	No	<p>1) There are currently two NERC approved projects filed at FERC (PRC-005-1.1b and PRC-005-2). NERC should consider waiting to proceed with this project until the current projects are ruled on and FERC provides further direction. 2) For 4.2.6, for reclosing capability, it is unclear what functionality is to be tested. Please define.3) For PRC-005-3 section 4.2.6.2, please provide the technical basis for this application of the Standard. Specifically, this application states for Automatic Reclosing: “Applied on 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.” Please provide the technical basis/reasoning for the 10-mile criteria. At a recent North American Transmission Forum Workshop on Protection System Maintenance Program it was implied that the 10 mile rule is for cases where a generator has a short connection to another company’s substation. Please clarify if this is the case.4) For PRC-005-3 section R1, consider adding the following language that is used for PRC-005-1.1b “each Generator Owner that owns a generation or generator interconnection Facility Protection System...” This is NERC-approved language that has been through the standards development process and has technical justification through Project 2010-07.5) Please provide the technical basis for R1.1 which requires battery testing for DC Supply Component Type Protection Systems to be time based. 6) Table 1-2 of PRC-005-3 requires functional testing of non-monitored communication systems on a 4 month cycle. Please specify NERC’s criteria for the functional testing (what attributes to be tested). Additionally, specifically define monitoring criteria and data intervals for continuous monitoring of communications systems (to see if check back (fail/no fail) monitoring is adequate).</p>
<p>Response: Thank you for your comment.</p> <p>1. The drafting team is acting in accordance with the schedule NERC provided to FERC, which outlines the timeframes by which NERC will respond, through the standards drafting process, to the directives of FERC Order 758. Specifically regarding reclosing relays (Footnote 37), FERC directed NERC to: “By July 30, 2012, NERC should submit to the Commission</p>		

Organization	Yes or No	Question 1 Comment
<p>either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.” Providing the schedule for addressing both reclosing relays and relays that do not respond to electrical quantities addressed this requirement of FERC Order 758.</p> <ol style="list-style-type: none"> 2. The specific functionality is defined within the requirements, specifically within Table 4. 3. The language in the Applicability section of the draft standard PRC-005-3 reflects the recommendations provided in the Planning Committee-approved guidance document titled, “Considerations for Maintenance and Testing of Autoreclosing Schemes”. This document was jointly composed by the NERC System Analysis and Modeling Subcommittee (SAMS) and the System Protection and Control Subcommittee (SPCS) to support the Project 2007-17.2 drafting team in the development of the requirements for PRC-005-3. Technical justification for the final recommendations provided in the document can be found on page 12 of the report. 4. The drafting team is precluded by the scope of the SAR for this project to make general content changes. 5. Please refer to the Supplementary Reference and FAQ document that was posted with the final, approved version of PRC-005-2 for more detailed information regarding battery maintenance and testing requirements and the reason for their exclusion from a Perform Based Maintenance (PBM) program (Section 9.2, Frequently Asked Questions, “Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?”). 6. The drafting team is precluded by the scope of the SAR for this project to make general content changes. 		
FirstEnergy	No	<ol style="list-style-type: none"> 1. FE supports the technical aspects and requirements of the standard. 2. FE is questioning the accuracy of the red-lining in this document. Many of the definitions were reflected as “new” when in fact only minor changes were made. 3. FE also questions why the drafting team is proposing deletions in the Revision History of the standard. Complete and accurate revision history is information that needs to be retained for future reference.
<p>Response: Thank you for your comment.</p> <ol style="list-style-type: none"> 1) Thank you for your support 2) The observation is correct. The version submitted by the drafting team reflected only the addition of ‘reclosing’ language. Using the “Compare” function in Microsoft Word resulted in the redlining of the entire definition(s). 3) The drafting team agrees and has included the complete Revision History in this draft of the standard. 		

Organization	Yes or No	Question 1 Comment
Ameren	No	<p>Ameren concurs with and also incorporates the SERC PCS comment regarding the interval for Automatic Reclosing exclusion studies by this reference. Ameren specific comments are: (1) We request that the SDT add a FAQ: “Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?” Answer: “Yes, Automatic Reclosing is a control function. The standard’s title ‘Protection System and Automatic Reclosing Maintenance’ clearly distinguishes its function from the Protection System. Automatic Reclosing is included in the PSMP because it is more concise than creating a parallel and essentially identical ‘Control System Maintenance Program’ for the two Automatic Reclosing component types.” (2) We request that the SDT add a FAQ: “Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly. This practice verifies the Control circuitry associated with Automatic Reclosing including the close coil. Do you agree?” Answer: “Yes, since the breaker does successfully close in your practice. The intent of the Unmonitored Control circuitry Maintenance Activity is for the entity to functionally prove the Automatic Reclosing control path is intact through the breaker close coil.” (3) We request that the SDT revise the Countable Event definition because as written it incorrectly implies that an Automatic Reclosing failure is a Misoperation. We believe that the Automatic Reclosing exclusion needs to be moved to a different sentence. (4) We request that the SDT add a FAQ: “Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.” Answer: “This test was chosen intentionally to err on the side of conservatism.” (5) We request that the SDT augment the FAQ 2.4.1 to include “IEEE Device No. 79” in referring to the Automatic Reclosing relay because this helps clarify the scope.</p>
<p>Response: Thank you for your comments.</p> <p>1) The Supplementary Reference and FAQ document was updated based on your input (Clause 15.8.1).</p> <p>2) The Supplementary Reference and FAQ document was updated based on your input (Clause 15.8.1).</p>		

Organization	Yes or No	Question 1 Comment
<p>3) The definition of “Countable Event” was modified to clarify that Misoperations are associated with Protection Systems. 4) The Supplementary Reference and FAQ document was updated based on your input (Clause 15.8.1). 5) The drafting team elected not to include the IEEE Device No 79 as an explicit reference within the Supplementary Reference and FAQ document.</p>		
<p>Independent Electricity System Operator</p>	<p>No</p>	<p>Comments: We only agree with the scope presented in the SAR. We do not agree with the proposed changes, as stated below. We suggest that the maintenance for Automatic Reclosing installed on the lines defined at Section 4.2.1 could be done at the same time with the maintenance of Protection Systems installed on those lines. Similarly, the maintenance for Automatic Reclosing used as an integral part of a SPS defined in Section 4.2.4 could be done at the same time with the maintenance for SPS. Please see the rationale below. The report attached as a supporting document mentions as a credible failure “a close signal is issued with no delay or less delay than is intended”. This failure should be classified as either a normal contingency or an extreme contingency, to be consistent with the TPL standards contingency classification. Section 4.2.6.1 states that Automatic Reclosing should be maintained “at generating plants substations where the total installed capacity is greater than the capacity of the largest generating unit within the Balancing Authority”. However, depending on the assumptions (how the system is stressed, extreme weather, etc.) and specific configurations, there may be other locations, where if the sequential three phase fault described in the Footnote 1 is applied, the total generation loss could be greater than the largest unit within the Balancing Authorities. The standard lacks a common methodology for testing sequential three phase faults described in the Footnote 1:</p> <ul style="list-style-type: none"> o The standard does not specify the conditions (extreme weather base case, extreme contingencies base case, how the generators are dispatched, etc.) or what would be the time delay between the first and second fault. All these conditions may affect the total generation loss. o The 10 circuit-miles criteria should be confirmed with the Planning Coordinators. o Depending on the location of the line being tested, different neighboring entities may be involved. o There should be a process in place to update the list of the Automatic Reclosing excluded from being maintained.

Organization	Yes or No	Question 1 Comment
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1) The standard does not specify how entities execute the maintenance of Protection Systems or Automatic Reclosing components. The maximum intervals in the Tables for Protection Systems and Automatic Reclosing activities are in alignment. 2) The SAMS/SPCS report describes the rationale for its recommendations. PRC-005-3 describes the maintenance requirements for Automatic Reclosing based on those recommendations. 3) The recommendation from the SAMS/SPCS report is based on a reclosing system malfunction for single-contingency conditions. The condition represented in the comment is a more severe multiple contingency condition. 4) The drafting team believes that the required analysis is sufficient. 5) The recommendation from the SAMS/SPCS report is based on a reclosing system malfunction for single-contingency conditions. The condition represented in the comment is a more severe multiple contingency condition. 6) Applicability section 4.2.6.2., in accordance with the recommendations from the SAMS/SPCS report, includes the 10 circuit mile criteria regardless of TP, PC, or BA area boundaries. 7) Entities are expected to be in compliance at all times following the implementation period, and should have current documentation supporting their compliance. An additional Implementation Plan has been developed to address conditions where changes in the Balancing Authority Area result in additional locations becoming subject to the Applicability. 		
Dominion	No	<p>Dominion agrees with most points and conceptually supports the SDT effort to limit additional applicability of this to those facilities identified in the Considerations for Maintenance and Testing of Autoreclosing Schemes report. We are however concerned that footnote 1 requires 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 generation in the Interconnection exceeding the largest unit within the Balancing Authority Area where the Automatic Reclosing is applied.” We do not believe that most Distribution Providers or Generator Owners have access to the information, or staff with necessary skills to make such assessments. In fact, we are not confident that entities with such access and skilled staff can make such as assertion. At best we believe an entity with the necessary access and skills could perform an analysis and indicate whether acceptable voltages, flows,</p>

Organization	Yes or No	Question 1 Comment
		<p>angles and stability would be adversely impacted by incorrect operation of an Automatic Reclosing. We do not believe such entity could determine whether or not an incorrect operation would “....result in a total loss of generation in the Interconnection exceeding the largest unit within the Balancing Authority Area where the Automatic Reclosing is applied.”We therefore conceptually support most of the standard but request the SDT consider adding a requirement that the Transmission Planner provide a list of those facilities where incorrect operation of Automatic Reclosing has been shown to result in such loss or alternatively to identify facilities where incorrect operation could be shown to result in violation of IROLs.</p>
<p>Response: Thank you for your comments.</p> <ul style="list-style-type: none"> 1) The footnote is an option available to Automatic Reclosing owners for excluding the associated components from a maintenance program. 2) It is the responsibility of the Transmission Owner, Generator Owner, and Distribution Provider with Automatic Reclosing to apply the standard and to perform the necessary evaluations to exclude otherwise-applicable Automatic Reclosing from their PSMP if they desire to do so. 		
<p>Florida Municipal Power Agency</p>	<p>No</p>	<p>FMPA is generally supportive of the changes to the standard to accommodate Reclosing Relays as directed by FERC. We have one comment: The SDT should recognize that there are a number of small BAs and that the Applicability 4.2.6.1 would be better stated as the largest generator within the Reliability Coordinator area as opposed to the largest generator in the Balancing Authority area (e.g., for some BAs, the largest generator in their area is less than 10 MW and not even registered). If left unchanged, FMPA would recommend a Negative vote.</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team revised the applicability to clarify that the applicable locations are 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.”</p>		
<p>Hydro One Networks Inc.</p>	<p>No</p>	<p>ï€ We do not agree with Footnote 1 in the standard which places the onus on the</p>

Organization	Yes or No	Question 1 Comment
		<p>equipment owner of the reclosing relays to demonstrate which reclosing relays can be excluded by making the determinations outlined in the footnote. This is clearly the role of the Reliability Coordinator or Planning Coordinator and not the equipment owner. Consequently, we believe that the applicability of this standard should be expanded to RCs and/or PCs in order to properly conduct the sort of studies asked for in the standard. i€ Also, the standard assumes that all relays are in scope and entities have to systematically exclude relays based on the footnote. We don't agree with this approach since it is onerous and leaves room for interpretations. We suggest that standard is changes so that the onus is placed on the RC or PC to identify such relays. i€ Section 4.2.6.3 is not specific enough in terms of in-scope reclosing used in an SPS. Use of the word "integral part of an SPS" is subject to interpretation and may require details of the SPS not readily available to the owner of the reclosing relays. i€ We propose that the maintenance for Automatic Reclosing installed on the lines defined at Section 4.2.1 should be done at the same time with the maintenance of Protection Systems installed on those lines. If the owner of the two relays is not the same, we recommend that the standard requires coordination between two entities. Similarly, the maintenance for Automatic Reclosing used as an integral part of a SPS defined in Section 4.2.4 should be done at the same time with the maintenance for SPS. The revision of the standard should only reflect these changes. Please see the rational below:The report attached as a supporting document mentions as a credible failure "a close signal is issued with no delay or less delay than is intended". This failure should be classified as either a normal contingency or an extreme contingency. The classification is important because the TPL standards define different study conditions based on contingency classification. Sections 4.2.6.1 states that Automatic Reclosing should be maintained "at generating plants substations where the total installed capacity is greater than the capacity of the largest generating unit within the Balancing Authority". However, depending on the assumptions (how the system is stressed, extreme weather, etc.) and specific configurations, there may be other locations, where if the double three phase fault described in the Footnote 1 is applied, the total generation loss could be greater than the largest unit within the Balancing Authorities. The standard lacks a common methodology for performing the double three phase</p>

Organization	Yes or No	Question 1 Comment
		<p>fault described in the Footnote 1: "The standard does not specify the conditions (extreme weather base case, extreme contingencies base case, how the generators are dispatched, etc.) or what would be the time delay between the first and second fault. All these conditions may affect the total generation loss." The 10 circuit-miles criteria should be confirmed with the Planning Coordinators." Depending on the location of the line being tested, different neighboring entities may be involved." There should be a process in place to update the list of the Automatic Reclosing excluded from being maintained.</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1) It is the responsibility of the Transmission Owner, Generator Owner, and Distribution Provider with Automatic Reclosing to apply the standard and to perform the necessary evaluations to exclude otherwise-applicable Automatic Reclosing from their PSMP if they desire to do so. 2) The standard does not specify how entities execute the maintenance of Protection Systems or Automatic Reclosing components. These can be performed together or separately based on the entity's processes. The maximum intervals in the Tables for Protection Systems and Automatic Reclosing activities are in alignment. 3) The SAMS/SPCS report describes the rationale for its recommendations. PRC-005-3 describes the maintenance requirements for Automatic Reclosing based on those recommendations. 4) The recommendation from the SAMS/SPCS report is based on a reclosing system malfunction for single-contingency conditions. The condition represented in the comment is a more severe multiple contingency condition. 5) Applicability section 4.2.6.2., in accordance with the recommendations from the SAMS/SPCS report, includes the 10 circuit mile criteria regardless of TP, PC, or BA area boundaries 6) Entities are expected to be in compliance at all times following the implementation period, and should have current documentation supporting their compliance. An additional Implementation Plan has been developed to address conditions where changes in the Balancing Authority Area result in additional locations becoming subject to the Applicability. 		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP is generally supportive of the changes that the drafting team

Organization	Yes or No	Question 1 Comment
(Occidental Chemical Corporation)		<p>has made to PRC-005-2 and supporting documentation to address FERC Order 758. First and foremost, we agree that the definition of “Protection System” should not be modified as it has implications to any standard that uses the term. This far exceeds the scope of FERC’s directive - which only identifies recloser maintenance as a reliability imperative. Second, we believe that the underlying technical basis for the identification of recloser relays that “can affect the reliability” of the BES is sound. The analysis performed by NERC’s System Analysis and Modeling and System Protection and Control Subcommittees (SAMS-SPCS) is compelling in our view. In this manner, the industry and CEAs can focus on those components which may pose risk to the local system - and not expend resources on those which do nothing to improve electric service delivery. However, as a Generator Owner, we are not sure how we will capture the information we need to conduct an analysis of our recloser relays. We can approach our Balancing Authority to have them provide the “capacity of the largest generating unit” within their control area - but have no recourse if they refuse to respond due to security or anti-competitive reasons. Even if this is not an issue, it seems plausible that an extended outage of the BA’s largest generator may re-set PRC-005-3’s applicability threshold downward. If this happens, we may be required to re-evaluate our equipment base on a moment’s notice. We don’t believe it is the drafting team’s intent to establish thresholds which may change in this manner. It would be far simpler if an Interconnect-wide capacity threshold could be established within PRC-005-3. Those Balancing Authorities that require a lower threshold could communicate their expectations to their base as they see fit.</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. Thank you for your support. 2. Thank you for your support. 3. Thank you for your support. 4. The drafting team believes that BAs will be willing to share the relevant information; note that this information may not include the identification of the largest BES generator in the Balancing Authority Area, but only the gross capacity of that 		

Organization	Yes or No	Question 1 Comment
<p>generator.</p> <p>5. This is a planning-time-frame horizon standard, and the drafting team believes that extended outages would be addressed by means of operating changes.</p> <p>6. It would be inappropriate to establish an interconnection-wide threshold. The drafting team developed a second implementation plan, "Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area", in consideration of the scenario you describe.</p>		
American Electric Power	No	<p>It is not clear exactly which sort of automatic reclosing behavior(s) the proposed changes are attempting to prevent. Accidental reclosing? Failure to reclose? Providing clarity on this fundamental question will help industry in providing sound comments and feedback regarding PRC-005-3. Does mentioning "interlock circuits" in the second bullet under Automatic Reclosing (page 2 of redline) refer narrowly to circuitry inside breaker mechanisms or does it also include lockout strings associated with lockout relays?</p>
<p>Response: Thank you for your comment.</p> <p>The report by NERC SAMS and SPCS describes the behavior to be avoided as premature autoreclosing that has the potential to cause generating unit or plant instability. The drafting team removed the text regarding "interlock circuits" from the definition.</p>		
Lincoln Electric System	No	<p>LES is concerned with how components of a reclosing system would be identified if an automatic line isolation scheme is included within a reclosing scheme. For instance, in some configurations, if a trip were to occur on a transmission line, one reclose is performed. If the line immediately trips again (i.e., the fault is not cleared), the line is automatically isolated with a line switch followed by a second reclose. This is done in order to pick up the load on a transformer that may be on the same line terminal at the substation. However, in the event there is a failure of the line switch, the second reclose is cancelled. In consideration that this would affect reclosing, LES asks that the drafting team provide further clarification as to whether the components associated with the line switch operation would be included as part of the PSMP as well. Additionally, if reclosing is supervised by a sync-check function, whether included</p>

Organization	Yes or No	Question 1 Comment
		<p>in the relay performing the reclosing or else in a separate relay, should that relay, and the voltage inputs needed to do sync-check, be included in the PSMP also? To ensure a consistent understanding amongst registered entities, LES recommends the drafting team add clarifying language to Applicability Section 4.2.6 or else provide further guidance within the Supplementary Reference and FAQ document.</p>
<p>Response: Thank you for your comments.</p> <p>As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature autoreclosing that has the potential to cause generating unit or plant instability. Therefore, the drafting team believes that, if the reclosing application addressed falls within the standard, the requirements apply, regardless of any sectionalizing in the vicinity. However, supervisory capabilities such as sync-check or line switch status are not included.</p>		
ReliabilityFirst	No	<p>No, the reclosing relays in the Applicability section were overly restricted. Improper operation of reclosing relays can exacerbate fault conditions and severely damage equipment that affects the long term reliability of the Bulk Power System. The Applicability section limits the facilities concerning automatic reclosing to those integral to an SPS or substations (and those one bus away) where the total installed generating plant capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area. This bar is so high that substations with units as high as 1200 MVA may not be covered by this revised standard. The capacity limit should either be removed or reduced to no more than half the largest generating unit within a BA. Also, the definition of Automatic Reclosing should include supervisory elements like synchronism check or dead-line check as these can be integral parts of the reclosing scheme.</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team requested guidance from the NERC SAMS and SPCS regarding the applicability, as well as suggested maximum maintenance intervals and minimum maintenance activities. In response to this request, SAMS and SPCS studied various concerns regarding automatic reclosing, and determined that only those conditions being addressed in the Applicability of PRC-005-3 needed to be addressed. The maximum maintenance intervals and minimum maintenance activities for the applicable</p>		

Organization	Yes or No	Question 1 Comment
components are described in Table 4.		
ISO RTO Council Standards Review Committee	No	<p>The IRC members compliment the SDT in using the recommendations provided in the SAMS/SPCS Order 758 Autoreclosing Report for the applicability of this standard directive to specific reclosing relays. By using these recommendations, Transmission Owners are provided guidance and reduced burden that should satisfy the Commission conclusion in the Order that “specific requirements fo selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System.” The IRC members are not directly impacted by the PRC-005 requirements from a compliance standpoint because we are generally not Transmission Owners. We are raising these questions to highlight the lack of communications between the stakeholder industry experts and the regulator directing technical requirements on the industry . As everyone in the industry knows, seven years’ experience with the ERO has caused significant burdens on meeting compliance requirements with numerous requirements being in effect and entities having to significantly increase resources in compliance and not always justifying whether such expenses are a benefit to the end consumer. NERC must develop processes and form relationships with the regulators who have these specific technical concerns to bring their concerns and issues to the industry experts in a more direct and efficient manner to avoid delays in standards development and approval and expending more resources in the regulatory process rather through a technical process. We question whether the approach the SDT has taken to address the FERC Directive in Order 758 addresses the core reliability concern that the Order seems to raise. First, the Order states that reclosing relays are not explicitly identified as part of the “Protection System” and if it plays a part in the “Protection System” to “achieve or meet system performance requirements” or “can exacerbate fault conditions when not properly maintained and coordinated” then there could be a gap in the maintenance and testing of the relays. Second the Order recognizes that certain parties in comments to the NOPR believe reclosing relays are used not for reliability reasons but for business purposes in restoration post-contingency. Further commenters stated that specific call outs for reclosing relays in PRC-005 are not necessary because reclosing relays are already integral to an entity’s relay maintenance</p>

Organization	Yes or No	Question 1 Comment
		<p>program. Nevertheless, FERC has directed NERC to add reclosing relays to the standard. There is no further technical justification for adding reclosing relays to the standards. The referenced language from the Order can be challenged by a protection system designer in that a reclosing relay may not be integral to “achieve or meet system performance requirements” nor “can exacerbate fault conditions” because they may have been designed to provide only restoration of service for customer satisfaction and be in a part of the system that cannot exacerbate a fault condition (e.g. tap configuration). Does a registered entity subject to this requirement have the ability to demonstrate a particular reclosing relay does not meet the apparent reliability concern specified in the Order and exclude those reclosing relays from the compliance program? An all inclusive approach to apply the PRC-005 requirements for all reclosing relays may have little to no reliability benefit to the grid. In addition, we offer the following comments for the SDT’s consideration to achieve consistency in the terms used and the precise devices that the revised standard should apply:</p> <p>a. Definition of PSMP: the term “Automatic Reclosing” should not be capitalized since it is indicated that the term is defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms. With this term not to be balloted and included in the Glossary, it should be in lower case.</p> <p>b. Order 758 directed NERC to include “reclosing relays” that can affect the reliable operation of the Bulk-Power System. Automatic reclosing is an act or intent, not a device. It is the latter that needs to be maintained and tested for continued functionality, not the former. Therefore, we suggest that the term “Automatic Reclosing” be replaced with “reclosing devices” or “reclosing relays” in the revised PSMP definition, in Sections A.1, A.3 and A.4.2.6, and throughout the standard where “automatic reclosing” is addressed/referenced.</p> <p>c. We interpret the FERC directive to require not just the automatic reclosing devices/relays be included in PRC-005, but also the relays/devices that may be used for manual reclosing. In other words, both automatic and manual reclosing devices/relays need to be included in the standard. To enable this applicability, we suggest not removing the word “automatic” where it appears.</p>

Organization	Yes or No	Question 1 Comment
<p>Response: Thank you for your response. To address your suggestions:</p> <ul style="list-style-type: none"> a) The drafting team agrees with you and un-capitalized the term “Automatic Reclosing” within the definition of PSMP. b) The drafting team considers "reclosing" to be a noun and "automatic" to be an adjective. The term "Reclosing relays" does not capture the all of the components that need to be maintained to meet the objectives of the standard. The drafting team requested guidance from the NERC SAMS and SPCS regarding the applicability, as well as suggested maximum maintenance intervals and minimum maintenance activities. In response to this request, SAMS and SPCS studied various concerns regarding automatic reclosing, and determined that only those conditions being addressed in the Applicability of PRC-005-3 needed to be addressed. c) The drafting team’s use of the terms "reclosing" and “automatic reclosing” are consistent with the use of the terms within IEEE standards. It is clear from the SAMS - SPCS report that automatic reclosing, not manual reclosing, is the concern that needs to be addressed by the standard. 		
<p>Northeast Power Coordinating Council</p>	<p>No</p>	<p>The maintenance for Automatic Reclosing installed on the lines defined at Section 4.2.1 should be done at the same time with the maintenance of Protection Systems installed on those lines. Similarly, the maintenance for Automatic Reclosing used as an integral part of a SPS defined in Section 4.2.4 should be done at the same time as the maintenance for a SPS. This should be reflected in this revision of the Standard. The Considerations for Maintenance and Testing of Autoreclosing Schemes report attached as a supporting document mentions as a credible failure “a close signal is issued with no delay or less delay than is intended”. This failure should be classified as either a normal contingency or an extreme contingency. The classification is important because the TPL standards define different study conditions based on contingency classifications. How are interconnections to be considered in Applicability Section 4.2.6 Automatic Reclosing? Section 4.2.6.1 states that Automatic Reclosing should be maintained “at generating plant substations where the total installed capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area”. However, depending on the assumptions used for system configurations, there may be other locations where if the double three phase fault described in Footnote 1 is applied, the total generation loss could be greater than the largest unit within the</p>

Organization	Yes or No	Question 1 Comment
		<p>Balancing Authority. Also, should the criteria be based on largest single source loss rather than largest generating unit? Otherwise, there is no mechanism that triggers review of applicability of this standard. For example, what if the largest generating unit within the BA Area is removed permanently from service? This is applicable in the Northeast, where TO and GO functions are performed by different entities/owners. The BA is the entity that determines the largest single source loss in its area; they would also be the proper functional entity to identify the generator locations in 4.2.6.1. The TPL or the BAL standards could then include a trigger mechanism to review applicability of 4.2.6 to GOs and TOs for a change in the largest single source loss criteria/limit. From a Registration Criteria perspective, the terms “unit” and “plant” as employed in the Registration Criteria suggest a two-part Applicability test. The first part is a comparison between the single “largest generating unit” and a larger multi-unit generating plant located at a single site (i.e., the term a “plant” as used in NERC Rules of Procedure, Appendix 5B NERC Statement of Compliance Registry Criteria). In this first part of the test the sum of the capacity ratings of the smaller individual units exceeds the single “largest generating unit” within the Balancing Authority Area. This is compared with a single “largest generating unit.” The second part of the Applicability test relates to the “generating plant substations.” In this phrase the word “substations” is plural. This plural wording suggests that the multi-unit generating plant feeds more than one substation. Suggest the following alternatives to the wording of Section 4.2.6.1: “Where generating plant substations are interconnected locally at the generating plant site, or adjacent to the generating plant site, and applied on BES Elements at the generating plant substations.” Or “Automatic Reclosing is applicable where the total site installed generating plant capacity is greater than the capacity of the largest generating unit within the Balancing Authority Area or when 4.2.6.3 applies.” Applicability Section 4.2.6.2 addresses the electrical and geographical proximity of the “generating plant substations” interconnections by stating “one bus away” and “less than 10 circuit-miles from the generating plant substation.” For clarification, suggest revising Section 4.2.6.2 to read “Where generating plant substations are interconnected at a distance from the generating plant site, applied on BES Elements at substations located one bus away from generating plant substations</p>

Organization	Yes or No	Question 1 Comment
		<p>when the substation is less than 10 circuit-miles from the generating plant substation.” What is the technical justification for the 10 circuit-miles? It may be necessary to confirm the 10 circuit miles with the Planning Coordinator. It is not clear if a substation “one bus away from generating plants” that meets the criteria in 4.2.6.2 and includes buses at two voltage levels, separated by a power transformer, is considered as one bus, or as two buses separated by a power transformer. If the former applies, reclosing relays on elements at only one of the substation buses would be included in this standard. If a reclosing relay is found non-functional during maintenance activity and has to be removed from service for an extended period of time, which in turn fully removes automatic reclosing functionality, is it still identified as an Unresolved Maintenance Issue? The final SAMS-SPCS report states that if “No close signal is issued under conditions that meet the intended design conditions, (...) this failure mode does not create any additional considerations for inclusion of autoreclosing relays in PRC-005”, which implies that it would not be identified as an Unresolved Maintenance Issue. Footnote 1 is not explicit as to the reclosing operation referred to. The Requirement appears to address only three pole, single shot reclosing. There is no reference to single pole reclosing or cases where multiple shot reclosing may be utilized. A more generalized statement should be considered: Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that, in the event of a close-in permanent fault, the reclosing utilized does not result in a total loss of generation in the Interconnection exceeding the largest unit within the Balancing Authority Area where the Automatic Reclosing is applied. Rationale should be provided to describe the system conditions to be considered for studying the three phase fault described in Footnote 1. Footnote 1 places the burden on the owner of the reclosing relays to demonstrate which reclosing relays can be excluded by making the determinations outlined in the footnote. This should be the role of the Reliability Coordinator or Planning Coordinator and not the equipment owner. Consequently, we believe that the applicability of this standard should be expanded to RCs and/or PCs in order to properly conduct the sort of studies asked for in the standard. Section 4.2.6.3 is not specific enough with regard to reclosing used in an SPS. The use of the word “integral part of an SPS” is subject to</p>

Organization	Yes or No	Question 1 Comment
		<p>interpretation and may require details of the SPS that will not be readily available to the owner of the reclosing relays. There should be a process in place to update the list of the Automatic Reclosing excluded from being maintained. The standard must consider that neighboring entities may be involved in the lines being tested.</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1) The standard does not specify how entities execute the maintenance of Protection Systems or Automatic Reclosing components. These can be performed together or separately based on the entity’s processes. The maximum intervals in the Tables for Protection Systems and Automatic Reclosing activities are in alignment. 2) The SAMS/SPCS report describes the rationale for its recommendations. PRC-005-3 describes the maintenance requirements for Automatic Reclosing based on those recommendations. 3) Applicability section 4.2.6.2., in accordance with the recommendations from the SAMS/SPCS report, includes the 10 circuit mile criteria regardless of TP, PC, or BA Area boundaries. 4) The recommendation from the SAMS/SPCS report is based on a reclosing system malfunction for single-contingency conditions. The condition represented in the comment is a more severe multiple contingency condition. 5) Entities are expected to be in compliance at all times following the implementation period, and should have current documentation supporting their compliance. An additional Implementation Plan has been developed to address conditions where changes in the Balancing Authority Area result in additional locations becoming subject to the Applicability. 6) “Plant” and “Unit”, as used in the Applicability are correct and align with the Registry Criteria. 7) Applicability section 4.2.6.2., in accordance with the recommendations from the SAMS/SPCS report, includes the 10 circuit mile criteria regardless of TP, PC, or BA Area boundaries 8) Individual buses, as described in Applicability section 4.2.6.2, would be separated by BES Elements, whether transformers or lines. 9) The described condition would be an Unresolved Maintenance Issue if it cannot be completed by the end of the scheduled maintenance interval. 10) As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature 		

Organization	Yes or No	Question 1 Comment
<p>autoreclosing that has the potential to cause generating unit or plant instability. Therefore, the drafting team believes that, if the reclosing application addressed falls within the standard, the requirements apply, whether the reclosing is three-phase or single-phase, or multiple shot or single shot.</p> <p>11) The recommendation from the SAMS/SPCS report is based on a reclosing system malfunction for single-contingency conditions. The condition represented in the comment is a more severe multiple contingency condition.</p> <p>12) Automatic reclosing components that are an “integral part” of a Special Protection System (SPS) would be Automatic Reclosing that is necessary for the SPS to function properly and provide the outcome intended. If failure or inadvertent operation of Automatic Reclosing keeps an SPS from performing its intended function, the requirements of PRC-005-3 would apply to that equipment.</p> <p>13) Entities are expected to be in compliance at all times following the implementation period, and should have current documentation supporting their compliance. An additional Implementation Plan has been developed to address conditions where changes in the Balancing Authority Area result in additional locations becoming subject to the Applicability.</p>		
American Transmission Company	No	The PRC-005 standard is directed at the Transmission Owner (TO), not the Transmission Planner (TP). The TO may not have the ability to perform the analysis that is required to identify exclusions and ATC recommends that the SDT address this issue.
<p>Response: Thank you for your comments.</p> <p>The footnote is an option available to Automatic Reclosing owners for excluding the associated components from a maintenance program.</p>		
CenterPoint Energy	No	The SAMS/SPCS study of automatic reclosing identifies 1 circuit-mile impedance as typically adequate to prevent generating unit instability and that 10 circuit-miles impedance is a sufficient margin. CenterPoint Energy requests that the SDT reevaluate the technical basis for selecting 10 circuit-miles as “sufficient margin” and incorporating this distance into the Applicable Facilities section 4.2.6.2. Since the SAMS/SPCS study states that 1 circuit mile impedance is adequate, it is possible that 5

Organization	Yes or No	Question 1 Comment
		circuit-miles or some other distance will provide a sufficient margin.
<p>Response: Thank you for your comments.</p> <p>In accordance to a request, SAMS and SPCS developed the recommendations within their report. SAMS believes that 10 circuit miles was an appropriate criterion providing sufficient margin. The SAMS and SPCS groups have the expertise to make that determination.</p>		
SERC Protection and Controls Subcommittee	No	Under the Facilities Section, the drafting team included Footnote #1 which allows an exclusion of certain locations that meet the test criteria; however, there is no stated time frame to re-validate the results of stated test. We recommend that the drafting team specifies a re-validation period of 60 months.
<p>Response: Thank you for your comments.</p> <p>Entities are expected to be in compliance at all times following the implementation period, and should have current documentation supporting their compliance. An additional Implementation Plan has been developed to address conditions where changes in the Balancing Authority Area result in additional locations becoming subject to the Applicability.</p>		
Pepco Holdings Inc & Affiliates	No	<p>We agree with the reasoning behind NERC’s System Analysis and Modeling Subcommittee (SAMS) recommendation to limit the applicability of automatic reclosing to only those installations that would impact the reliability of the BES. The three criteria (Sections 4.2.6.1, 4.6.2.2, and 4.6.2.3) identified in the PRC-005-3 draft and FAQ document seem reasonable and appropriate. However, additional clarification is needed to ensure uniform interpretation of these criteria. Consider the following scenario. Suppose a certain generating plant has 500 MVA of generation interconnected at a 230kV bus, 300 MVA interconnected at a 138kV bus, and 200 MVA interconnected at a 69kV bus. There are autotransformers connecting the 138kV bus to both the 230kV and 69kV busses. 1) How is total plant capacity to be calculated? Is it the sum of all generation capacity at the plant (500 + 300 + 200 = 1000 MVA), even though it is not all interconnected at the same bus, and some of it is connected below 100kV? Or, should the aggregate generation capacity interconnected on each bus be</p>

Organization	Yes or No	Question 1 Comment
		<p>evaluated separately for those lines connected to that bus? Depending on the size of the autotransformers which interconnect the three busses, the transformer thru impedance could be comparable to, or exceed, the equivalent impedance of 10 circuit miles of line. If this were the case, it would seem that evaluation of plant capacity should be permitted to be calculated on an individual bus basis, rather than a total plant basis. Also, can the 200 MVA of generation interconnected at the 69kV bus be excluded from the total plant capacity, since it is interconnected below 100kV, and therefore not BES generation? Section 4.2.6.1 should be re-worded to provide clarity and eliminate confusion on how to evaluate this plant capacity calculation. Also, specific examples illustrating how to apply this criterion would be helpful in the FAQ. 2) Section 4.2.6.1 states that it applies to “all BES elements at generating plant substations...”. The transmission line (including both ends) is considered a BES element. Therefore one might interpret this as applying to both ends of any BES element that terminates on a generating plant substation. We believe the intent of 4.2.6.1 is to only apply to the automatic reclosing schemes on the line terminals located at the generating station and to not apply to the automatic reclosing schemes on the opposite ends of the lines remote from the generating plant substation. Automatic reclosing schemes on lines terminating on generating stations usually employ a leader-follower philosophy, with the remote terminal programmed as the reclose initiate terminal, and the generating station end of the line reclosing only upon a successful restoration of the far end. A reclosing mal-function at the far terminal should have no consequences for the generating plant, provided there is no other electrically short (within 10 circuit miles) transmission path from the far terminal back to the generating plant. To provide clarity, Section 4.2.6.1 should be re-worded as follows: “Applied on the terminals of BES Elements located at generating plant substations...”. For consistency, Section 4.2.6.2 should also be re-worded as follows: “Applied on the terminals of BES Elements located at substations...”. Also, specific examples and clarifications in the FAQ would also be helpful. 3) For consistency, when determining plant capacity and capacity of the largest generating unit within the Balancing Authority Area, rated generator nameplate MVA ratings should be used rather than published seasonal MW values. 4) The NERC SAMS review concluded</p>

Organization	Yes or No	Question 1 Comment
		<p>that automatic reclosing mal-performance affects BES reliability when “inadvertent reclosing near a generating station subjects the generation station to severe fault stresses”. The concern appears to be potential shaft torque damage, or instability, of rotating machines to automatic reclosing mal-performance. That being the case, generation sources that are not subject to severe fault stresses, such as inverter based generation, or static reactive sources (SVC’s, capacitor banks, etc.) should not be included in the calculation of total plant capacity. However, since synchronous condensers are subject to the same fault stresses as synchronous generators they should probably be included in the aggregate plant generation calculation, providing they are interconnected at 100kV, or above.</p>
<p>Response: Thank you for your comments:</p> <ol style="list-style-type: none"> 1. According to NERC Rules of Procedure, Appendix 5B – NERC Statement of Compliance Registry Criteria, “plant” is used to refer to a multi-unit generating plant located at a single site. 2. The Applicability sections you reference were revised in consideration of your comments. 3. After further discussion, the drafting team determined that gross aggregated plant ratings and gross generator ratings should be used. The standard was revised accordingly. 4. Footnote 1 covers the condition you reference. 		
Duke Energy	No	<p>We believe the modifications to the PRC-005-2 Applicability section 4.2.6.1 should recognize that the reliability issue is inadvertent reclosing, and therefore applicability on BES Elements at generating plant substations should be limited to the timing and sync check functions of reclosing. There is no need to include all DC circuitry, etc. because if a problem existed aside from timing and sync check, it would just prevent reclosing. Also, rather than being focused only on plant capacity, there should be some recognition that plant location on the BES is also a consideration. Duke Energy believes the Applicability section 4.2.6.2 should be based on a technical assessment as illustrated in the SAMS/SPCS paper. This type of assessment should be based on a simulation of a close-in-three-phase fault for twice the normal clearing time. This simulation would capture a minimum trip-close time delay.</p>

Organization	Yes or No	Question 1 Comment
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. The standard requires verification that Automatic Reclosing, upon initiation, does not issue a premature closing command. The definition of Automatic Reclosing and the associated maintenance activities in Table 4 were revised for clarity. 2. Footnote 1 allows the entity to exclude generator buses when they do not meet the SAMS recommendation. 		
<p>exelon and its Affiliates</p>	<p>No</p>	<p>We understand the concerns related to reclosing relays however we do not agree that these devices should be included in PRC-005 because reclosing relays are not a protective device. The current system stability studies do not rely on automatic reclosing to maintain the reliability of the Bulk Power System.</p>
<p>Response: Thank you for your comment.</p> <p>As you point out reclosing relays are not protective devices. That is the reason these devices were not added to the Protective System definition. The reclosing relays addressed in this standard are a very narrowly defined set of devices. These devices could cause plant instability if they failed causing an instantaneous close after trip on a large generation bus. The drafting team is acting in accordance with the schedule NERC provided to FERC, which outlines the timeframes by which NERC will respond, through the standards drafting process, to the directives of FERC Order 758. Specifically regarding reclose relays (Footnote 37), FERC directed NERC to: “By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.”</p>		
<p>Entergy Services, Inc.</p>	<p>Yes</p>	<p>Entergy agrees with the inclusion of the reclosing relay maintenance requirement except for how the terminology is addressed. Entergy suggests not adding of the term Automatic Reclosing; instead add reclosing relay and the associated circuitry description under Protection System definition.</p>
<p>Response: Thank you for your comment.</p> <p>The drafting team chose not to add reclosing devices to the definition because they are not protective devices.</p>		
<p>Tacoma Power</p>	<p>Yes</p>	<p>Tacoma Power has the following comments regarding improvements to the</p>

Organization	Yes or No	Question 1 Comment
		<p>standard:1. *Regarding 4.2.6.1 and 4.2.6.2, there are some generating plants that may be in a different Balancing Authority area than the Transmission Owner with which they interconnect. This may complicate the determination of applicability of Automatic Reclosing under PRC-005-3.2. Regarding 4.2.6.2, would it be necessary to maintain Automatic Reclosing components per PRC-005-3 on BES Elements “facing” an applicable generating plant? For example, assume that a 5-circuit-mile long line connects Generating Plant A with Substation B. Would Automatic Reclosing components at Substation B on the connecting line need to be maintained per PRC-005-3? It seems unlikely that a failure of the Automatic Reclosing in this scenario would have adverse reliability impact to the BES. Of course, this assumes that there is not another generating plant within 10 circuit miles connected to Substation B. 3. Consider a substation located within 10 circuit miles of two or more generating plants, none of which individually applies under 4.2.6.1. Furthermore, assume that these generating plants collectively have a total installed generating plant capacity greater than the capacity of the largest generating unit within the Balancing Authority area? Would the substation apply to 4.2.6.2? 4. In 4.2.6.2, only Automatic Reclosing applied on BES Elements is applicable. What if there is a non-BES radial line connected to the substation? It seems that the reliability impact of improper Automatic Reclosing on this non-BES Element could be as high as that for improper Automatic Reclosing on a BES Element connected to the substation.</p>
<p>Response: Thank you for your comments:</p> <ol style="list-style-type: none"> 1. Applicability section 4.2.6.2., in accordance with the recommendations from the SAMS/SPCS report, includes the 10 circuit mile criteria regardless of TP, PC, or BA Area boundaries. 2. Applicability sections 4.2.6.1 and 4.2.6.2 were revised based on your comments. 3. No, the scenario you describe does not meet the Applicability criteria. 4. Applicability sections 4.2.6.1 and 4.2.6.2 were revised for clarity. 		
MRO NERC Standards Review Forum	Yes	The NSRF supports the draft standard PRC-005-3 addressing automatic reclosing as correct and appropriate.

Organization	Yes or No	Question 1 Comment
<p>Response: Thank you for your comments.</p>		
<p>Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing</p>	<p>Yes</p>	<p>Under the Facilities Section, the drafting team included Footnote #1 which allows an exclusion of certain locations that meet the test criteria; however, there is no stated time frame to re-validate the results of stated test. We recommend that the drafting team specifies a re-validation period.</p>
<p>Response: Thank you for your comments.</p> <p>Entities are expected to be in compliance at all times following the implementation period, and should have current documentation supporting their compliance. An additional Implementation Plan has been developed to address conditions where changes in the Balancing Authority Area result in additional locations becoming subject to the Applicability.</p>		
<p>SPP Standards Review Group</p>	<p>Yes</p>	<p>Would misoperations of automatic reclosing relays as specified in 4.2.6 have to be reported in PRC-004-2?</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team chose not to add reclosing devices to the definition of Protection System because they are not protective devices. As such, PRC-004-2 would not be affected.</p>		
<p>Bonneville Power Administration</p>	<p>Yes</p>	
<p>PacifiCorp</p>	<p>Yes</p>	

Organization	Yes or No	Question 1 Comment
Vandolah Power Company	Yes	
Self	Yes	
OPG	Yes	
Idaho Power Company	Yes	

2. The drafting team developed an Implementation Plan for PRC-005-3 based on the Implementation Plan for PRC-005-2 to address the addition of Automatic Reclosing. Do you agree with the implementation plan regarding Automatic Reclosing? If not, please provide specific suggestions for improvement.

Summary Consideration:

Many commenters agreed with the Implementation Plan.

A few commenters questioned the complexity of the Implementation Plan for PRC-005-3 which includes the Protection System aspects of PRC-005-2 and adds the new aspects of Automatic Reclosing from PRC-005-3. The plan addresses the implementation of the PRC-005-2 requirements based on the approval date of PRC-005-2 and adds the implementation of the revised requirements that include Automatic Reclosing based on the approval date of PRC-005-3. This approach provides clarity regarding the implementation dates for maintenance of Protection System and Automatic Reclosing Components. The drafting team crafted the Implementation Plan with guidance from NERC legal staff and believes the Implementation Plan is clear once carefully reviewed.

Several commenters had concerns related to applicable facilities changing because of generation changes within the Balancing Authority Area. The drafting team developed a second Implementation Plan to alleviate these concerns. The document titled: "Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area", is posted with the draft standard.

Organization	Yes or No	Question 2 Comment
ACES Standards Collaborators	No	(1) The SDT needs to clarify the implementation plan. The document is confusing because it focuses on the PRC-005-2 standard, which is not yet FERC-approved. As a result, this implementation plan is a moving target. Why not wait until PRC-005-2 gets approved before initiating another project for the same standard? This would reduce some of the timing issues and confusion.(2) Why is the drafting team revising a standard that has not been approved by the Commission yet? The second version was only filed in February 2013, and the timing of this project is premature. It is quite possible that the Commission could remand or direct revisions to parts of the standard and issue other directives associated with the version 2, which would then need to be

Organization	Yes or No	Question 2 Comment
		<p>addressed. This project is untimely and should be postponed until there is a final order from FERC. At that point, there may be justification to continue with this project, expand the scope of the SAR to address any new directives that may be included in a final order of PRC-005-2, or to determine that a guidance document is an appropriate way to satisfy the FERC orders.(3) Again, the drafting team needs to consider other methods of answering FERC directives. Not every directive needs to be addressed by developing or revising a standard. Adding reclosing relays to PRC-005 only complicates the most-violated non-CIP standard. There is enough concern about this standard already and the drafting team should consider alternative means to address the reclosing relay issue besides a standard revision.(4) This project contains similar timing issues as CIP version 4 and CIP version 5 because it is being developed prior to FERC issuing a final order on the previous version of the standard. The timing is problematic; registered entities will be forced to constantly be focusing on the next standard. The implementation plan should provide additional time, similar to PRC-005-2’s two intervals, to allow registered entities enough time to adjust their PSMT programs for Protection Systems, and then have additional time to adjust their PSMT plan and implement auto-reclosing relays.(5) Thank you for the opportunity to comment.</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. The drafting team crafted the Implementation Plan with guidance from NERC legal staff. The Implementation Plan addresses the implementation of PRC-005-2 requirements based on the approval dates of PRC-005-2 and adds implementation of PRC-005-3 requirements based on its approval date. The drafting team believes the Implementation Plan is clear once carefully reviewed. 2. The drafting team disagrees with the assertion that the timing of this project is premature. The drafting team is complying with the NERC schedule provided to FERC describing how NERC will address the directives issued in Order No.758. 3. NERC, as well as other entities, provided comments in response to FERC NOPR discussions regarding requirements related to maintenance of automatic reclosing, essentially proposing equally-effective options. FERC, in response, directed that NERC specifically include requirements related to maintenance of automatic reclosing within PRC-005. 4. The drafting team does not believe the standards developed for PRC-005 are similar to the CIP versions 4 and 5 in that 		

Organization	Yes or No	Question 2 Comment
<p>PRC-005-3 simply adds maintenance requirements for Automatic Reclosing Components and does not change the existing maintenance requirements for the Protection System Components covered in PRC-005-2. The Implementation Plan for PRC-005-3 does provide the additional time for implementing the changes associated with PRC-005-3.</p> <p>5. Thank you for providing comments.</p>		
Manitoba Hydro	No	(23) General - use the acronyms for “Protection System Maintenance Program”, PSMP and for “Board of Trustees”, BOT. Both terms are referenced multiple times within the Implementation Plan document.
<p>Response: Thank you for your comment.</p> <p>The use of acronyms is optional. The drafting team chose not to in the instances cited.</p>		
exelon and its Affiliates	No	<p>1. 4.2.6.1 - How would a PRC-005-3 relay engineer determine or be made aware of “the capacity of the largest generating unit within the Balancing Authority Area” at any given moment in time? (e.g., suppose a large Nuclear unit that historically constituted the largest unit in a given BAA gets retired? This could present an unintentional compliance trap for the PRC-005-3 owner, unless this information is routinely updated and published as part of another NERC Standard, or by some other mechanism wherein the relay engineer could keep abreast of such changes in a timely manner).</p> <p>2. 4.2.6.1 - More clarity is needed on exactly what is meant by “generating plant substations”, since this collective phrase is not defined in NERC’s most recent Glossary of Terms, dated 05apr13. BGE example: Wagner Unit #4 Sync Breaker is physically located at Wagner Power Plant, but because the step-up voltage is 230kV, the output feeds into Brandon Shores 230kV substation, rather than the local 110kV substation where the other Wagner machines feed into. In this case, would Brandon Shores be considered the “generating plant substation” for Wagner Unit #4?</p> <p>3. 4.2.6.2 - The stated inclusion criteria “one bus away from generating plants specified in Section 4.2.6.1” introduces further interpretation difficulty when considering other common generating configurations, such as:</p> <p>1. The sync breaker is on the low voltage side of the GSU transformer and the GSU high side leads constitute a “short” transmission line</p>

Organization	Yes or No	Question 2 Comment
		<p>between the Plant (GO) and Substation (TO)2. Same as above but the sync breaker is located on the high side of the GSU and connects to the TO switchyard by the “short” transmission line.3. The sync breakers owned by the TO are located in the substation and connected to the high side of the GSU but operated by the GO, again at the other end of s short transmission line GO. (A legacy arrangement that results from the disintegration of formerly vertically integrated utilities)4. Sync breaker on the high side of the GSU at the plant, but there is a “long” transmission line connecting the sync breaker to a TO substation.</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. The Balancing Authority would have this information and would be able to provide it to entities. Each entity is responsible for disseminating the information within its own organization. Entities are expected to be in compliance at all times following the implementation period, and should have current documentation supporting their compliance. An additional Implementation Plan was developed to address conditions where changes in the Balancing Authority Area result in additional locations becoming subject to the Applicability. The drafting team developed a second Implementation Plan to alleviate these concerns. The document titled: “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area”, is posted with the draft standard. 2. According to the NERC Rules of Procedure, Appendix 5B – NERC Statement of Compliance Registry Criteria, “plant” is used to refer to a multi-unit generating plant located at a single site. 3. This comment is not related to the question posed on the Implementation Plan. However, the drafting team revised the Applicability clauses 4.2.6.1.and 4.2.6.2 of PRC-005-3 in consideration of your comments. 		
Self	No	It will take longer than the team suggests. Suggest a survey to determine a date the industry can adhere to, if a survey has not been performed yet.
<p>Response: Thank you for your comment.</p> <p>The drafting team believes the Implementation Plan is sufficient.</p>		
ReliabilityFirst	No	No, the implementation plan has an excessively long phased in approach that stretches

Organization	Yes or No	Question 2 Comment
		out to 13 years after regulatory approval or 14 years after NERC Board of Trustees adoption
<p>Response: Thank you for your comment</p> <p>The drafting team believes the Implementation Plan is sufficient.</p>		
Dominion	No	The implementation plan should utilize Transmission Planner (TP) notification to applicable entities rather than simply base the plan on the regulatory approval date to start the implementation timelines. This would allow the notified entities to have the same amount of time that is currently in the implementation plan upon notification from the Transmission Planner.
<p>Response: Thank you for your comment.</p> <p>The drafting team believes the Implementation Plan is sufficient.</p>		
Nebraska Public Power District	No	To implement, it would cause us to have to verify that the reclose actually works as part of the functional trip check. Otherwise, we have the breakers and relays already classified as NERC.
<p>Response: Thank you for your comment.</p> <p>The drafting team revised the maintenance activities within Table 4 in consideration of yours and others concerns.</p>		
American Electric Power	No	We are concerned by the second bullet in the General Considerations section where it states” Whether each component has last been maintained according to PRCâ€005â€02 (or the combined successor standard PRCâ€005â€03), PRCâ€005â€01b, PRCâ€008â€00, PRCâ€011â€00, PRCâ€017â€00, or a combination thereof.” This section implies obligations which reference standards outside of PRC-005-3 and including a standard which is not yet fully approved (PRC-005-02), essentially serving as Measures outside of the proposed standard. In addition, obligations have no place in an implementation plan if they are not also specified

Organization	Yes or No	Question 2 Comment
		<p>within the standard itself. This overall approach sets a bad precedent for the standards development process. AEP does not recommend basing an implementation date on a standard which has not been fully approved, as that could prove problematic if in this case PRC-005-2 fails to become fully approved by FERC but PRC-005-3 <i>is</i> approved. Ideally, we recommend that the implementation date be solely based on PRC-005-3. However, should the drafting team still wish to include PRC-005-2 in the implementation plan, perhaps it could instead state that “Unimplemented Protection System Component maintenance activities per PRC-005-2 will continue to be implemented in accordance with the PRC-005-2 implementation plan. In addition, the following Automatic Reclosing Component maintenance activities will be implemented as part of PRC-005-3...”</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team crafted the Implementation Plan with guidance from NERC legal staff. The Implementation Plan addresses the implementation of PRC-005-2 requirements based on the approval dates of PRC-005-2 and adds implementation of PRC-005-3 requirements based on its approval date. The drafting team believes the Implementation Plan is clear once carefully reviewed.</p>		
Entergy Services, Inc.	Yes	Entergy agrees with the addition of table 4 except for the terminology Automatic Reclosing.
<p>Response: Thank you for your comment.</p> <p>FERC directives from Order 758 instruct NERC to address “reclosing relays” within the reliability standards. In response to the technical report prepared by NERC SAMS and NERC SPCS, the drafting team developed the term, “Automatic Reclosing” to refer to the control circuitry associated with reclosing relays as well as the reclosing relays proper, and used this term throughout the modified standard and Implementation Plan.</p>		
FirstEnergy	Yes	FE agrees with the proposed Implementation Plan for V3.
<p>Response: Thank you for your comment and support.</p>		

Organization	Yes or No	Question 2 Comment
ISO RTO Council Standards Review Committee	Yes	We agree with the proposed implementation plan, but suggest that the term “Automatic Reclosing” with “reclosing devices” or “reclosing relays” be applied throughout the Implementation Plan document (see out comments under Q1, above).
<p>Response: Thank you for your comment and support.</p> <p>FERC directives from Order 758 instruct NERC to address “reclosing relays” within the reliability standards. In response to the technical report prepared by NERC SAMS and NERC SPCS, the drafting team developed the term, “Automatic Reclosing” to refer to the control circuitry associated with reclosing relays as well as the reclosing relays proper, and used this term throughout the modified standard and Implementation Plan.</p>		
SPP Standards Review Group	Yes	
Pepco Holdings Inc & Affiliates	Yes	
SERC Protection and Controls Subcommittee	Yes	
MRO NERC Standards Review Forum	Yes	
Northeast Power Coordinating Council	Yes	
Hydro One Networks Inc.	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Duke Energy	Yes	
Florida Municipal Power	Yes	

Organization	Yes or No	Question 2 Comment
Agency		
Bonneville Power Administration	Yes	
PacifiCorp	Yes	
Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
OPG	Yes	
Ingleside Cogeneration LP (Occidental Chemical Corporation)	Yes	
Ameren	Yes	
Tacoma Power	Yes	
Lincoln Electric System	Yes	
CenterPoint Energy	Yes	

Organization	Yes or No	Question 2 Comment
City of Tallahassee	Yes	
Independent Electricity System Operator	Yes	
Idaho Power Company	Yes	
City of Tallahassee	Yes	

END OF REPORT

Standard Development Roadmap

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

Development Steps Completed:

1. Standards Committee approved posting SAR and draft standard on January 17, 2013.
2. SAR posted for 30-day informal comment period from April 5, 2013 through May 6, 2013.
3. Draft 1 of PRC-005-3 posted for a 30-day formal comment period from April 5, 2013 through May 6, 2013.
4. Draft 2 of PRC-005-3 posted for a 45-day formal comment period from July 10, 2013 through August 23, 2013.

Description of Current Draft:

This is the second draft of the PRC-005-3. The standard modifies PRC-005-2 to address the directive issued by the Federal Energy Regulatory Commission in Order No.758 for “NERC to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System...”

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for a concurrent 45-day comment and ballot	July 2013
2. Conduct recirculation ballot	October 2013
3. BOT Adoption	November 2013

Definitions of Terms Used in Standard

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

Protection System Maintenance Program (PSMP) (NERC Board of Trustees Approved Definition)

— An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

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

Automatic Reclosing –

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

A. Introduction

- 1. Title:** **Protection System and Automatic Reclosing Maintenance**
- 2. Number:** PRC-005-3
- 3. Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
- 4. Applicability:**
 - 4.1. Functional Entities:**
 - 4.1.1** Transmission Owner
 - 4.1.2** Generator Owner
 - 4.1.3** Distribution Provider
 - 4.2. Facilities:**
 - 4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4** Protection Systems installed as a Special Protection System (SPS) for BES reliability.
 - 4.2.5** Protection Systems for 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 for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
 - 4.2.6** Automatic Reclosing¹, including:
 - 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

¹ Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

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

5. Effective Date: See Implementation Plan

B. Requirements

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

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. [*Violation Risk Factor:*

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

Medium] [Time Horizon: Operations Planning]

- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.
- For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)
- For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification

Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.3. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

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

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

1.4. Additional Compliance Information

None.

Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 3) Maintained a Segment with

Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				less than 60 Components OR 4) Failed to: <ul style="list-style-type: none"> • Annually update the list of Components, <li style="text-align: center;">OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, <li style="text-align: center;">OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance

Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance

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

E. Regional Variances

None

F. Supplemental Reference Document

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

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 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

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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 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
3	TBD	Revised to include Automatic Reclosing in maintenance programs	Project 2007-17.2 Revision to address the FERC directive in Order No.758 regarding Automatic Reclosing

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

² For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). 	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • 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

<p align="center">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)</p> <p align="center">Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

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

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3)		
Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

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

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	<p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate. <p>For microprocessor relays:</p> <ul style="list-style-type: none"> • 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.
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> • 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. <p>Alarming for power supply failure (See Table 2).</p>	12 Calendar Years	<p>Verify:</p> <ul style="list-style-type: none"> • 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
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • 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). <p>Alarming for change of settings (See Table 2).</p>	12 Calendar Years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). 	12 Calendar Years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an SPS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

**Table 4-2(b)
Maintenance Activities and Intervals for Automatic Reclosing Components
Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an SPS**

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

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

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

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

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences

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.

Countable Event – A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action, or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

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.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Standard Development Roadmap

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

Development Steps Completed:

1. Standards Committee approved posting SAR and draft standard on January 17, 2013.
2. SAR posted for 30-day informal comment period from April 5, 2013 through May 6, 2013.
3. Draft 1 of PRC-005-3 posted for a 30-day formal comment period from April 5, 2013 through May 6, 2013.
4. Draft 2 of PRC-005-3 posted for a 45-day formal comment period from ~~June 28~~ July 10, 2013 through August ~~12~~ 23, 2013.

Description of Current Draft:

This is the ~~first~~second draft of the PRC-005-3. The standard modifies PRC-005-2 to address the directive issued by the Federal Energy Regulatory Commission in Order No.758 for “NERC to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System...”

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for 30-day formal comment	April 2013
2.1. Post for a concurrent 45-day comment and initial ballot	July 2013
3.2. Conduct recirculation ballot	August <u>October</u> 2013
<u>3. BOT Adoption</u>	<u>November 2013</u>

Definitions of Terms Used in Standard

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

Protection System Maintenance Program (PSMP) (NERC Board of Trustees Approved

Definition) — An ongoing program by which Protection System and ~~Automatic automatic Reclosing reclosing~~ components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

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

Automatic Reclosing –

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay ~~through the close coil(s) of the circuit breakers or similar device but excluding breaker internal controls such as anti-pump and various interlock circuits.~~

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~~ Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

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the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables [4-1 through 4-2](#) which requires corrective action or a [Protection System](#) Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

A. Introduction

1. **Title:** Protection System and Automatic Reclosing Maintenance
2. **Number:** PRC-005-3
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Transmission Owner
 - 4.1.2 Generator Owner
 - 4.1.3 Distribution Provider
 - 4.2. **Facilities:**
 - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4 Protection Systems installed as a Special Protection System (SPS) for BES reliability.
 - 4.2.5 Protection Systems for 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 for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
 - 4.2.6 Automatic Reclosing¹, **including:**
 - 4.2.6.1 ~~Applied~~ Automatic Reclosing applied on ~~BES~~ 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

¹ Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 ~~Applied on~~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.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

5. Effective Date: See Implementation Plan

B. Requirements

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

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System ~~Component Type~~ and Automatic Reclosing ~~Components~~Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

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

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- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

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.

C. Measures

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

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-~~1~~ through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit
Self-Certification

Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.3. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

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

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p>OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p>OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p>OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p>NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p>OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p>OR</p> <ol style="list-style-type: none"> 3) Maintained a Segment with

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				less than 60 Components OR 4) Failed to: <ul style="list-style-type: none"> • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance

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

E. Regional Variances

None

F. Supplemental Reference Document

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

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

Version History

Version	Date	Action	Change Tracking
<u>0</u>	<u>April 1, 2005</u>	<u>Effective Date</u>	<u>New</u>
<u>1</u>	<u>December 1, 2005</u>	<ol style="list-style-type: none"> 1. <u>Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</u> 2. <u>Added “periods” to items where appropriate.</u> 3. <u>Changed “Timeframe” to “Time Frame” in item D, 1.2.</u> 	<u>01/20/05</u>
<u>1a</u>	<u>February 17, 2011</u>	<u>Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers</u>	<u>Project 2009-17 interpretation</u>
<u>1a</u>	<u>February 17, 2011</u>	<u>Adopted by Board of Trustees</u>	
<u>1a</u>	<u>September 26, 2011</u>	<u>FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)</u>	
<u>1.1a</u>	<u>February 1, 2012</u>	<u>Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility</u>	<u>Revision under Project 2010-07</u>
<u>1b</u>	<u>February 3, 2012</u>	<u>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.</u>	<u>Project 2009-10 Interpretation</u>
<u>1.1b</u>	<u>April 23, 2012</u>	<u>Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.</u>	<u>Revision under Project 2010-07</u>

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<u>1.1b</u>	<u>May 9, 2012</u>	<u>PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).</u>	
2	November <u>7</u> , 2012	Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0 <u>Adopted by Board of Trustees</u>	Complete revision <u>Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0</u>
3	TBD	Revision <u>Revised to include Automatic Reclosing into existing Version in maintenance programs</u>	Inclusion of <u>Project 2007-17.2 Revision to address the FERC directive in Order No.758 regarding Automatic Reclosing only</u>

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

² For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). 	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

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

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

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Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3)		
Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS. <i>(See Table 4-2(b) for SPS which include Automatic Reclosing.)</i>	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

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

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	<p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate. <p>For microprocessor relays:</p> <ul style="list-style-type: none"> • 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.
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> • 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. <p>Alarming for power supply failure (See Table 2).</p>	12 Calendar Years	<p>Verify:</p> <ul style="list-style-type: none"> • 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
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • 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). <p>Alarming for change of settings (See Table 2).</p>	12 Calendar Years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4.1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). 	12 Calendar Years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Unmonitored Control circuitry associated with Automatic Reclosing including the close coil.	12 Calendar Years	Verify the Automatic Reclosing control path including the close coil.
Control circuitry associated with Automatic Reclosing including the close coil whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

<u>Table 4-2(a)</u> <u>Maintenance Activities and Intervals for Automatic Reclosing Components</u> <u>Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS</u>		
<u>Component Attributes</u>	<u>Maximum Maintenance Interval</u>	<u>Maintenance Activities</u>
<u>Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.</u>	<u>12 Calendar Years</u>	<u>Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.</u>
<u>Control circuitry associated with Automatic Reclosing that is not part of an SPS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)</u>	<u>No periodic maintenance specified</u>	<u>None.</u>

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

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

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

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

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences

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 **e**Components.

Countable Event – A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action, or a **Protection System** Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

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.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Implementation Plan

Protection System and Automatic Reclosing Maintenance

PRC-005-3

Standards Involved

Approval:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Retirements:

- PRC-005-2 – Protection System Maintenance
- PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 – Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program
- PRC-011-0 – Undervoltage Load Shedding System Maintenance and Testing
- PRC-017-0 – Special Protection System Maintenance and Testing

Prerequisite Approvals:

N/A

Background:

Reliability Standard PRC-005-2 with its associated Implementation Plan was approved by the NERC Board of Trustees in November 2012 and has been filed with the applicable regulatory authorities for approval. The Implementation Plan for PRC-005-3 addresses both Protection Systems as outlined in PRC-005-2 and Automatic Reclosing components. PRC-005-3 establishes minimum maintenance activities for Automatic Reclosing Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-3 requires entities to revise the Protection System Maintenance Program by now including Automatic Reclosing Components. The implementation plan established under PRC-005-2 remains unchanged except for the addition of Automatic Reclosing Components required under PRC-005-3.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry-forward requirements from PRC-005-2, establish minimum maintenance activities for Protection System and Automatic Reclosing Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.

2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.
3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth in this document carries forward the implementation schedules contained in PRC-005-2 and includes changes needed to address the addition of Automatic Reclosing Components in PRC-005-3. According to the combined implementation plan in this document, entities must develop their revised Protection System Maintenance Program within twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees adoption of PRC-005-2. This anticipates that it will take approximately twelve (12) months to achieve regulatory approvals following the November 2012 adoption of PRC-005-2 by the NERC Board of Trustees.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standard PRC-005-3, in accordance with this implementation plan.

While entities are transitioning to the requirements of PRC-005-2, or the combined successor standard PRC-005-3, each entity must be prepared to identify:

- All of its applicable Protection System and Automatic Reclosing Components.
- Whether each component has last been maintained according to PRC-005-2 (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof.

For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active throughout the phased implementation period of PRC-005-3 and shall be applicable to an entity's Protection System Component maintenance activities not yet transitioned to PRC-005-3. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2.

The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees adoption.

Implementation Plan for Definition:

Protection System Maintenance Program – Entities shall use this definition when implementing any portions of R1, R2 R3, R4 and R5 which use this defined term.

Implementation Plan for Requirements R1, R2 and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30)

months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding

maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
6. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
7. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Implementation Plan Protection System and Automatic Reclosing Maintenance PRC-005-3

Standards Involved

Approval:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Retirements:

- PRC-005-2 – Protection System Maintenance
- PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 – Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program
- PRC-011-0 – Undervoltage Load Shedding System Maintenance and Testing
- PRC-017-0 – Special Protection System Maintenance and Testing

Prerequisite Approvals:

N/A

Background:

Reliability Standard PRC-005-2 with its associated Implementation Plan was approved by the NERC Board of Trustees in November 2012 and has been filed with the applicable regulatory authorities for approval. The Implementation Plan for PRC-005-3 addresses both Protection Systems as outlined in PRC-005-2 and Automatic Reclosing components. PRC-005-3 establishes minimum maintenance activities for Automatic Reclosing Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-3 requires entities to revise the Protection System Maintenance Program by now including Automatic Reclosing Components. The implementation plan established under PRC-005-2 remains unchanged except for the addition of Automatic Reclosing Components required under PRC-005-3.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry-forward requirements from PRC-005-2, establish minimum maintenance activities for Protection System and Automatic Reclosing Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.

2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.
3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth in this document carries forward the implementation schedules contained in PRC-005-2 and includes changes needed to address the addition of Automatic Reclosing Components in PRC-005-3. According to the combined implementation plan in this document, entities must develop their revised Protection System Maintenance Program within twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees adoption of PRC-005-2. This anticipates that it will take approximately twelve (12) months to achieve regulatory approvals following the November 2012 adoption of PRC-005-2 by the NERC Board of Trustees.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standard PRC-005-3, in accordance with this implementation plan.

While entities are transitioning to the requirements of PRC-005-2, or the combined successor standard PRC-005-3, each entity must be prepared to identify:

- All of its applicable Protection System and Automatic Reclosing Components.
- Whether each component has last been maintained according to PRC-005-2 (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof.

For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active throughout the phased implementation period of PRC-005-3 and shall be applicable to an entity's Protection System Component maintenance activities not yet transitioned to PRC-005-3. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2.

The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees adoption.

Implementation Plan for Definition:

Protection System Maintenance Program – Entities shall use this definition when implementing any portions of R1, R2 R3, R4 and R5 which use this defined term.

Implementation Plan for Requirements R1, R2 and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30)

months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding

maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
6. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
7. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area

Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)

This applies to PRC-005-3 and successor standards.

Additional applicable Automatic Reclosing Components may be identified because of the addition or retirement of generating units; or increases of gross generation capacity of individual generating units or plants within the Balancing Authority area.

In such cases, the responsible entities must complete the maintenance activities, described in Table 4, for the newly identified Automatic Reclosing Components prior to the end of the following calendar year unless documented prior maintenance fulfilling the requirements of Table 4 is available.

Unofficial Comment Form

Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) 2nd Draft of PRC-005-3

Please **DO NOT** use this form to submit comments. Please use the [electronic form](#) to submit comments on the 2nd draft of reliability standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance. Comments must be submitted by 8:00 p.m. Eastern **Friday, August 23, 2013**. If you have questions please contact [Al McMeekin](#) or by telephone at 803-530-1963.

The project page may be accessed by [clicking here](#).

Background Information:

On February 3, 2012, the Federal Energy Regulatory Commission (FERC) issued Order No. 758 approving an interpretation of NERC Reliability Standard PRC-005-1, Transmission and Generation Protection System Maintenance and Testing. In addition to approving the interpretation, the Commission directed that concerns identified in the preceding Notice of Proposed Rulemaking (NOPR) be addressed within the reinitiated PRC-005 revisions. The concerns raised in the NOPR pertain to automatic reclosing (autoreclosing) relays that are either “used in coordination with a Protection System to achieve or meet system performance requirements established in other Commission-approved Reliability Standards, or can exacerbate fault conditions when not properly maintained and coordinated,” in which case “excluding the maintenance and testing of these reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the Bulk-Power System.” To address these concerns, the Commission concludes that “specific requirements or selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System.”

In response to Order No. 758, the Protection System Maintenance and Testing Standard Drafting Team (SDT) drafted a Standard Authorization Request (SAR) to modify PRC-005 to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System. On May 10, 2012, the NERC Standards Committee (SC) accepted the SAR and authorized that it be posted for information only along with the 3rd draft of PRC-005-2. The NERC SC noted that PRC-005-2 was in the final stages of the development process, having passed a successive ballot with 79 percent approval on June 27, 2012 and was scheduled to be presented for approval at the November NERC Board of Trustees meeting. Consequently, in recognition of the consensus achieved, the NERC SC determined that the drafting team should complete the development of PRC-005-2 and immediately thereafter begin work on PRC-005-3 which would reflect the necessary revisions to address reclosing relays.

The SDT also requested the NERC Planning Committee (PC) provide the technical input necessary to develop the appropriate revisions to PRC-005. The NERC PC instructed the NERC System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) to jointly perform a technical study to determine which reclosing relays should be addressed within PRC-005 and provide advice regarding the appropriate maintenance intervals and activities for those relays. The final report was approved by the NERC Planning Committee on November 14, 2012 and provided to the SDT for guidance in developing PRC-005-3.

In Order No. 758, the Commission also directed NERC to file, by July 30, 2012, either a completed project, or an informational filing providing “a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.” On July 30, 2012, NERC submitted an informational filing in compliance with Order No. 758 with a proposed schedule for addressing reclosing relays. The project number and name is as follows: Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)

On January 17, 2013, the NERC SC authorized the draft SAR be posted for formal industry comment concurrent with project development. The SAR as well as the first draft of PRC-005-3 was posted for a 30-day comment period from April 5, 2013 through May 6, 2013. The PSMT SDT has responded to the comments from the initial posting and incorporated pertinent suggestions into the second draft of the standard.

Draft 2 of PRC-005-3 is posted for a 45-day formal comment period from July 10, 2013 through August 23, 2013. Ballot pools are forming now through August 8, 2013. A ballot and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted August 14-23, 2013.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained. Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

NOTE: The Standards Authorization Request specifically limits this project to modifying PRC-005-2 to address the addition of reclosing relays which can affect the reliability of the BES, and specifically precludes general improvements to PRC-005-2.

1. In response to comments, the drafting team revised the previously-posted draft of PRC-005-3 and the Supplementary Reference and FAQ document. Do you agree with these changes? If not, please provide specific suggestions for improvement.

Yes

No

Comments:

2. In response to comments, the drafting team developed an “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area” Do you agree with this additional Implementation Plan? If not, please provide specific suggestions for improvement.

Yes

No

Comments:

E-mail completed form to
sarcomm@nerc.com

Standard Authorization Request Form

Request Date January 17, 2013

SAR Requester Information	SAR Type (Check a box for each one that applies.)	
Individual, Group, or Committee Name Protection System Maintenance Standard Drafting Team	<input type="checkbox"/>	New Standard
Primary Contact (if Group or Committee) Charles Rogers	<input checked="" type="checkbox"/>	Revision to existing Standard
Company or Group Name Chairman, Protection System Maintenance Standard Drafting Team	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail Charles.Rogers@cmsenergy.com	<input type="checkbox"/>	Project Identified in Reliability Standards Development Plan (Project Number and Name:)
Telephone 517-788-0027	<input checked="" type="checkbox"/>	Modification to NERC Glossary term or addition of new term

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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Brief Description of Proposed Standard Modifications/Actions (In three sentences or less, summarize the proposed actions a drafting team will be responsible for implementing.)

The Standard Drafting Team shall modify NERC Standard PRC-005-2 to explicitly address the maintenance and testing of reclosing relays which can affect the reliable operation of the Bulk Electric System.

The Standard Drafting Team shall not make general revisions to the standard in content or arrangement.

Need (Explain why the Standard is being developed or modified. Clearly indicate why the actions being proposed are needed for maintaining or improving bulk power system reliability, including an assessment of the reliability and market interface impacts. This is similar to the Purpose statement in a Reliability Standard.)

Reclosing relays are applied to facilitate automatic restoration of system components following a Protection System operation. In certain circumstances the misoperation of reclosing relays can impact the reliability of the Bulk Electric System. The Federal Energy Regulatory Commission, in paragraphs 16-27 of Order No. 758, directed that NERC include reclosing relays that “can affect the reliable operation of the Bulk-Power System” within NERC Standard PRC-005.

Modifying the standard in this fashion will assure that those reclosing relays that can affect the reliability of the Bulk Electric System are properly maintained.

No market interface impacts are anticipated.

Goals (Describe what must be accomplished in order to meet the above need. This section would become the Requirements in a Reliability Standard.)

The revision to PRC-005-2 may require that the definition of Protection System be revised to add reclosing relays.

The Applicability section of the Standard must be modified to describe explicitly those devices that entities are to maintain in accordance with the revised standard.

The Tables of minimum maintenance activities and maximum maintenance intervals will require modification to include appropriate intervals and activities.

Finally, the informative Supplementary Reference Document (provided as a technical reference for PRC-005-2) should be modified to provide the rationale for the maintenance activities and intervals within the modified standard, as well as to provide application guidance to industry.

Objectives and/or Potential Future Metrics (Describe what the potential measure or criteria for success may be for determining the successful implementation of this request. Provide ideas for potential metrics to be developed and monitored in the future relative to this request, if any.)

Successful implementation of the modified standard will assure that the devices being added will perform as needed for the conditions anticipated by those performance requirements.

Detailed Description (In three paragraphs or more, provide a detailed description of the proposed actions a drafting team will be responsible for executing so that the team can efficiently implement this request. While you will check applicability boxes on the following page, this description must include proportional identification of to whom the standard should apply among industry participants.)

The drafting team shall:

1. Consider revision of the title of the Standard to appropriately address the added devices.
2. Modify the Purpose of the Standard as necessary to address reclosing relays.
3. Consider modification of the definition of Protection System to add reclosing relays.
4. Modify the Applicability section of PRC-005-2 to describe explicitly those devices that entities are to maintain in accordance with the revised standard.
5. Modify the Tables within PRC-005-2 to include maximum intervals and minimum activities appropriate for the devices being addressed, with consideration for the technology of the devices and for any condition monitoring that may be in place for those devices.
6. Modify the Measures and Violation Severity Levels as necessary to address the modified requirements.
7. Modify the informative Supplementary Reference Document (provided as a technical reference for PRC-005-2) to provide the rationale for the maintenance activities and intervals within the modified standard, as well as to provide application guidance to industry.

OPTIONAL: Technical Analysis Performed to Support Justification (Provide the results of any technical study or analysis performed to justify this request. Alternatively, if deemed necessary, propose a technical study or analysis that should be performed prior to a related standard development project being initiated in response to this request.)

The NERC System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) have jointly performed a technical study to determine which reclosing relays should be addressed within PRC-005 and provide advice regarding appropriate maintenance intervals and activities for those relays. The related report was approved by the NERC Planning Committee on November 14, 2012.

The Standard Drafting Team shall use this report as an aid in developing appropriate revisions to PRC-005-2.

Reliability Functions

The Standard(s) May Apply to the Following Functions <i>(Check box for each one that applies.)</i>		
<input type="checkbox"/>	Regional Entity	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
<input type="checkbox"/>	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
<input type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/>	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/>	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/>	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
<input type="checkbox"/>	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
<input type="checkbox"/>	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input checked="" type="checkbox"/>	Transmission Owner	Owens and maintains transmission facilities.
<input type="checkbox"/>	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input checked="" type="checkbox"/>	Distribution Provider	Delivers electrical energy to the End-use customer.
<input checked="" type="checkbox"/>	Generator Owner	Owens and maintains generation facilities.
<input type="checkbox"/>	Generator Operator	Operates generation unit(s) to provide real and reactive power.

<input type="checkbox"/>	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/>	Market Operator	Interface point for reliability functions with commercial functions.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles <i>(Check box for all that apply.)</i>	
<input checked="" type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input checked="" type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
Does the proposed Standard(s) comply with all of the following Market Interface Principles? <i>(Select 'yes' or 'no' from the drop-down box.)</i>	
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	

- | |
|--|
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.
Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

Related Standards

Standard No.	Explanation
NONE	

Related Projects

Project ID and Title	Explanation
NONE	

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

E-mail completed form to
sarcomm@nerc.com

Standard Authorization Request Form

Request Date January 17, 2013

SAR Requester Information	SAR Type (Check a box for each one that applies.)	
Individual, Group, or Committee Name Protection System Maintenance Standard Drafting Team	<input type="checkbox"/>	New Standard
Primary Contact (if Group or Committee) Charles Rogers	<input checked="" type="checkbox"/>	Revision to existing Standard
Company or Group Name Chairman, Protection System Maintenance Standard Drafting Team	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail Charles.Rogers@cmsenergy.com	<input type="checkbox"/>	Project Identified in Reliability Standards Development Plan (Project Number and Name:)
Telephone 517-788-0027	<input checked="" type="checkbox"/>	Modification to NERC Glossary term or addition of new term

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Suite 600, North Tower
Atlanta, GA 30326
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Brief Description of Proposed Standard Modifications/Actions (In three sentences or less, summarize the proposed actions a drafting team will be responsible for implementing.)

The Standard Drafting Team shall modify NERC Standard PRC-005-2 to explicitly address the maintenance and testing of reclosing relays which can affect the reliable operation of the Bulk Electric System.

The Standard Drafting Team shall not make general revisions to the standard in content or arrangement.

Need (Explain why the Standard is being developed or modified. Clearly indicate why the actions being proposed are needed for maintaining or improving bulk power system reliability, including an assessment of the reliability and market interface impacts. This is similar to the Purpose statement in a Reliability Standard.)

Reclosing relays are applied to facilitate automatic restoration of system components following a Protection System operation. In certain circumstances the misoperation of reclosing relays can impact the reliability of the Bulk Electric System. The Federal Energy Regulatory Commission, in paragraphs 16-27 of Order No. 758, directed that NERC include reclosing relays that “can affect the reliable operation of the Bulk-Power System” within NERC Standard PRC-005.

Modifying the standard in this fashion will ~~impact Bulk Electric System (BES) reliability by~~ assuring that those reclosing relays that can affect the reliability of the Bulk Electric System are properly maintained (~~installed to meet performance goals of approved NERC Standards~~) are properly maintained so that they may be expected to perform properly.

No market interface impacts are anticipated.

Goals (Describe what must be accomplished in order to meet the above need. This section would become the Requirements in a Reliability Standard.)

The revision to PRC-005-2 may require that the definition of Protection System be revised to add reclosing relays.

The Applicability section of the Standard must be modified to describe explicitly those devices that entities are to maintain in accordance with the revised standard.

The Tables of minimum maintenance activities and maximum maintenance intervals will require modification to include appropriate intervals and activities.

Finally, the informative Supplementary Reference Document (provided as a technical reference for PRC-005-2) should be modified to provide the rationale for the maintenance activities and intervals within the modified standard, as well as to provide application guidance to industry.

|

Objectives and/or Potential Future Metrics (Describe what the potential measure or criteria for success may be for determining the successful implementation of this request. Provide ideas for potential metrics to be developed and monitored in the future relative to this request, if any.)

Successful implementation of the modified standard will assure that the devices being added will perform as needed for the conditions anticipated by those performance requirements.

Detailed Description (In three paragraphs or more, provide a detailed description of the proposed actions a drafting team will be responsible for executing so that the team can efficiently implement this request. While you will check applicability boxes on the following page, this description must include proportional identification of to whom the standard should apply among industry participants.)

The drafting team shall:

1. Consider revision of the title of the Standard to appropriately address the added devices.
2. Modify the Purpose of the Standard as necessary to address reclosing relays.
3. Consider modification of the definition of Protection System to add reclosing relays.
4. Modify the Applicability section of PRC-005-2 to describe explicitly those devices that entities are to maintain in accordance with the revised standard.
5. Modify the Tables within PRC-005-2 to include maximum intervals and minimum activities appropriate for the devices being addressed, with consideration for the technology of the devices and for any condition monitoring that may be in place for those devices.
6. Modify the Measures and Violation Severity Levels as necessary to address the modified requirements.
7. Modify the informative Supplementary Reference Document (provided as a technical reference for PRC-005-2) to provide the rationale for the maintenance activities and intervals within the modified standard, as well as to provide application guidance to industry.

OPTIONAL: Technical Analysis Performed to Support Justification (Provide the results of any technical study or analysis performed to justify this request. Alternatively, if deemed necessary, propose a technical study or analysis that should be performed prior to a related standard development project being initiated in response to this request.)

The NERC System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) have jointly performed a technical study to determine which reclosing relays should be addressed within PRC-005 and provide advice regarding appropriate maintenance intervals and activities for those relays. The related report was approved by the NERC Planning Committee on November 14, 2012.

The Standard Drafting Team shall use this report as an aid in developing appropriate revisions to PRC-005-2.

Reliability Functions

The Standard(s) May Apply to the Following Functions <i>(Check box for each one that applies.)</i>		
<input type="checkbox"/>	Regional Entity	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
<input type="checkbox"/>	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
<input type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/>	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/>	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/>	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
<input type="checkbox"/>	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
<input type="checkbox"/>	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input checked="" type="checkbox"/>	Transmission Owner	Owns and maintains transmission facilities.
<input type="checkbox"/>	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input checked="" type="checkbox"/>	Distribution Provider	Delivers electrical energy to the End-use customer.
<input checked="" type="checkbox"/>	Generator Owner	Owns and maintains generation facilities.
<input type="checkbox"/>	Generator Operator	Operates generation unit(s) to provide real and reactive power.

<input type="checkbox"/>	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/>	Market Operator	Interface point for reliability functions with commercial functions.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles <i>(Check box for all that apply.)</i>	
<input checked="" type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input checked="" type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
Does the proposed Standard(s) comply with all of the following Market Interface Principles? <i>(Select 'yes' or 'no' from the drop-down box.)</i>	
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	

- | |
|--|
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.
Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

Related Standards

Standard No.	Explanation
NONE	

Related Projects

Project ID and Title	Explanation
NONE	

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Violation Risk Factor and Violation Severity Level Justifications

Project 2007-17.2 PRC-005-3

Protection System and Automatic Reclosing Maintenance

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-005-2 - Protection System Maintenance.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Maintenance and Testing Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria – VRFs

High Risk Requirement

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

Medium Risk Requirement

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

Lower Risk Requirement

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

FERC VRF Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the VRF Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

PRC-005-3 Protection System and Automatic Reclosing Maintenance is a revision of PRC-005-2 Protection System Maintenance with the stated purpose: To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

PRC-005-3 has five (5) requirements that address the inclusion of Automatic Reclosing. A Table of minimum maintenance activities and maximum maintenance intervals has been added to PRC-005-2 to address FERC's directives from Order 758. The revised standard requires that entities develop an appropriate Protection System Maintenance Program (PSMP), that they implement their PSMP, and that, in the event they are unable to restore Automatic Reclosing Components to proper working order while performing maintenance, they initiate the follow-up activities necessary to resolve those maintenance issues.

The requirements of PRC-005-3 map one-to-one with the requirements of PRC-005-2. The drafting team did not revise the VRFs for the requirements of PRC-005-3.

PRC-005-3 Requirements R1 and R2 are related to developing and documenting a Protection System Maintenance Program. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violations of these requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

PRC-005-3 Requirements R3 and R4 are related to implementation of the Protection System Maintenance Program. The SDT determined that the assignment of a VRF of High was consistent with the NERC criteria that that violation of these requirements could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are assigned a VRF of High.

PRC-005-3 Requirement R5 relates to the initiation of resolution of unresolved maintenance issues, which describe situations where an entity was unable to restore a Component to proper working order during the performance of the maintenance activity. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violation of this requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

NERC Criteria - VSLs

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
<p>Missing a minor element (or a small percentage) of the required performance</p> <p>The performance or product measured has significant value as it almost meets the full intent of the requirement.</p>	<p>Missing at least one significant element (or a moderate percentage) of the required performance.</p> <p>The performance or product measured still has significant value in meeting the intent of the requirement.</p>	<p>Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital Component.</p> <p>The performance or product has limited value in meeting the intent of the requirement.</p>	<p>Missing most or all of the significant elements (or a significant percentage) of the required performance.</p> <p>The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.</p>

FERC Order on VSLs

In its June 19, 2008 Order on VSLs, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

- Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

- Guideline 2a: A violation of a “binary” type requirement must be a “Severe” VSL.
- Guideline 2b: Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: VSL Assignment Should Be Consistent with the Corresponding Requirement

- VSLs should not expand on what is required in the requirement.

Guideline 4: VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

- . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF and VSL Justifications

VRF and VSL Justifications – PRC-005-3, R1	
Proposed VRF	Medium
NERC VRF Discussion	Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so only one VRF was assigned. The requirement utilizes Parts to identify the items to be included within a Protection System Maintenance Program. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-2 Requirement R1.

VRF and VSL Justifications – PRC-005-3, R1			
Proposed VRF	Medium		
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs:</p> <p>Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:</p> <p>This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.</p>		
Proposed VSL – PRC-005-3, R1			
Lower	Moderate	High	Severe
<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p>OR</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p>OR</p>	<p>The responsible entity failed to establish a PSMP.</p> <p>OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>

Proposed VSL – PRC-005-3, R1			
Lower	Moderate	High	Severe
The responsible entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1)		The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	

VRF and VSL Justifications – PRC-005-3, R1	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R1

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R2	
Proposed VRF	Medium
NERC VRF Discussion	Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-2 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for.

VRF and VSL Justifications – PRC-005-3, R2			
Proposed VRF	Medium		
	Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-3, R2			
Lower	Moderate	High	Severe
The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	N/A	The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP

Proposed VSL – PRC-005-3, R2			
Lower	Moderate	High	Severe
			<p>OR</p> <p>2) Failed to reduce countable events to no more than 4% within five years</p> <p>OR</p> <p>3) Maintained a Segment with less than 60 Components</p> <p>OR</p> <p>4) Failed to:</p> <ul style="list-style-type: none"> • Annually update the list of Components, <p>OR</p> <ul style="list-style-type: none"> • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, <p>OR</p> <ul style="list-style-type: none"> • Annually analyze the program activities and results for each Segment.

VRF and VSL Justifications – PRC-005-3, R2	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R2

Guideline 2b: VSL Assignments that Contain Ambiguous Language	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R3	
Proposed VRF	High
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-3, R3			
Lower	Moderate	High	Severe
For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2.

VRF and VSL Justifications – PRC-005-3, R3	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R3

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R4	
Proposed VRF	High
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-3, R4			
Lower	Moderate	High	Severe
For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.

VRF and VSL Justifications – PRC-005-3, R4	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R4

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R5	
Proposed VRF	Medium
NERC VRF Discussion	Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only requirement within approved Standards, PRC-004-2a Requirements R1 and R2 contain a similar requirement and is assigned a HIGH VRF. However, these requirements contain several subparts, and the VRF must address the most egregious risk related to these subparts, and a comparison to these requirements may be irrelevant. PRC-022-1 Requirement R1.5 contains only a similar requirement, and is assigned a MEDIUM VRF. FAC-003-2 Requirement R5 contains only a similar requirement, and is assigned a MEDIUM VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system.

VRF and VSL Justifications – PRC-005-3, R5			
Proposed VRF	Medium		
	<p>However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.</p>		
Proposed VSL – PRC-005-3, R5			
Lower	Moderate	High	Severe
The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

VRF and VSL Justifications – PRC-005-3, R5	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirement in PRC-005-2 has not been implemented; consequently, there is no prior level of compliance.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R5

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2007-17.2 PRC-005-3

Protection System and Automatic Reclosing Maintenance

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-005-2 - Protection System Maintenance.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Maintenance and Testing Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria – VRFs

High Risk Requirement

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

Medium Risk Requirement

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

Lower Risk Requirement

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

FERC VRF Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC’s Definition of the VRF Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC’s definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC’s VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC’s Reliability Standards and implies that these requirements should be assigned a “High” VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

PRC-005-3 Protection System and Automatic Reclosing Maintenance is a revision of PRC-005-2 Protection System Maintenance with the stated purpose: To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

PRC-005-3 has five (5) requirements that address the inclusion of Automatic Reclosing. A Table of minimum maintenance activities and maximum maintenance intervals has been added to PRC-005-2 to address FERC’s directives from Order 758. The revised standard requires that entities develop an appropriate Protection System Maintenance Program (PSMP), that they implement their PSMP, and that, in the event they are unable to restore Automatic Reclosing Components to proper working order while performing maintenance, they initiate the follow-up activities necessary to resolve those maintenance issues.

The requirements of PRC-005-3 map one-to-one with the requirements of PRC-005-2. The drafting team did not revise the VRFs for the requirements of PRC-005-3.

PRC-005-3 Requirements R1 and R2 are related to developing and documenting a Protection System Maintenance Program. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violations of these requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

PRC-005-3 Requirements R3 and R4 are related to implementation of the Protection System Maintenance Program. The SDT determined that the assignment of a VRF of High was consistent with the NERC criteria that that violation of these requirements could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are assigned a VRF of High.

PRC-005-3 Requirement R5 relates to the initiation of resolution of unresolved maintenance issues, which describe situations where an entity was unable to restore a Component to proper working order during the performance of the maintenance activity. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violation of this requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

NERC Criteria - VSLs

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
<p>Missing a minor element (or a small percentage) of the required performance</p> <p>The performance or product measured has significant value as it almost meets the full intent of the requirement.</p>	<p>Missing at least one significant element (or a moderate percentage) of the required performance.</p> <p>The performance or product measured still has significant value in meeting the intent of the requirement.</p>	<p>Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital Component.</p> <p>The performance or product has limited value in meeting the intent of the requirement.</p>	<p>Missing most or all of the significant elements (or a significant percentage) of the required performance.</p> <p>The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.</p>

FERC Order on VSLs

In its June 19, 2008 Order on VSLs, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

- Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

- Guideline 2a: A violation of a “binary” type requirement must be a “Severe” VSL.
- Guideline 2b: Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: VSL Assignment Should Be Consistent with the Corresponding Requirement

- VSLs should not expand on what is required in the requirement.

Guideline 4: VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

- . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF and VSL Justifications

VRF and VSL Justifications – PRC-005-3, R1	
Proposed VRF	Medium
NERC VRF Discussion	Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so only one VRF was assigned. The requirement utilizes Parts to identify the items to be included within a Protection System Maintenance Program. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-2 Requirement R1.

VRF and VSL Justifications – PRC-005-3, R1			
Proposed VRF	Medium		
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs:</p> <p>Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:</p> <p>This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.</p>		
Proposed VSL – PRC-005-3, R1			
Lower	Moderate	High	Severe
<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p>OR</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p>OR</p>	<p>The responsible entity failed to establish a PSMP.</p> <p>OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>

Proposed VSL – PRC-005-3, R1			
Lower	Moderate	High	Severe
The responsible entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1)		The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	

VRF and VSL Justifications – PRC-005-3, R1

<p>NERC VSL Guidelines</p>	<p>Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.</p>
<p>FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.</p>
<p>FERC VSL G2 VSL Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: N/A</p> <p>Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – PRC-005-3, R1

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R2	
Proposed VRF	Medium
NERC VRF Discussion	Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-2 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for.

VRF and VSL Justifications – PRC-005-3, R2			
Proposed VRF	Medium		
	Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-3, R2			
Lower	Moderate	High	Severe
The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	N/A	The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP

Proposed VSL – PRC-005-3, R2			
Lower	Moderate	High	Severe
			<p>OR</p> <p>2) Failed to reduce countable events to no more than 4% within five years</p> <p>OR</p> <p>3) Maintained a Segment with less than 60 Components</p> <p>OR</p> <p>4) Failed to:</p> <ul style="list-style-type: none"> • Annually update the list of Components, <p>OR</p> <ul style="list-style-type: none"> • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, <p>OR</p> <ul style="list-style-type: none"> • Annually analyze the program activities and results for each Segment.

VRF and VSL Justifications – PRC-005-3, R2	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R2

Guideline 2b: VSL Assignments that Contain Ambiguous Language	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R3	
Proposed VRF	High
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-3, R3			
Lower	Moderate	High	Severe
For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 .	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 .	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 .	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 .

VRF and VSL Justifications – PRC-005-3, R3	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R3

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R4	
Proposed VRF	High
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-3, R4			
Lower	Moderate	High	Severe
For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.

VRF and VSL Justifications – PRC-005-3, R4	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R4

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-3, R5	
Proposed VRF	Medium
NERC VRF Discussion	Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only requirement within approved Standards, PRC-004-2a Requirements R1 and R2 contain a similar requirement and is assigned a HIGH VRF. However, these requirements contain several subparts, and the VRF must address the most egregious risk related to these subparts, and a comparison to these requirements may be irrelevant. PRC-022-1 Requirement R1.5 contains only a similar requirement, and is assigned a MEDIUM VRF. FAC-003-2 Requirement R5 contains only a similar requirement, and is assigned a MEDIUM VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system.

VRF and VSL Justifications – PRC-005-3, R5			
Proposed VRF	Medium		
	<p>However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC’s criteria for a Medium VRF.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.</p>		
Proposed VSL – PRC-005-3, R5			
Lower	Moderate	High	Severe
The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

VRF and VSL Justifications – PRC-005-3, R5	
NERC VSL Guidelines	Meets NERC’s VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirement in PRC-005-2 has not been implemented; consequently, there is no prior level of compliance.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-3, R5

FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Supplementary Reference and FAQ

PRC-005-3 Protection System Maintenance

July 2013

RELIABILITY | ACCOUNTABILITY



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1. Introduction and Summary

Note: This supplementary reference for PRC-005-3 is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive, and, when approved, will supersede PRC-005-2.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-3 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the [NERC Glossary of Terms](#) used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- 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.

2.3 Applicability of New Protection System Maintenance Standards

The BES purpose is to transfer bulk power. The applicability language has been changed from the original PRC-005:

“...affecting the reliability of the Bulk Electric System (BES)...”

To the present language:

“...that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).”

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution

Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

NERC's approved definition of Bulk Electric System is:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.

The BES definition is presently undergoing the process of revision.

Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a [June 14, 2007 Informational Filing](#).

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Special Protection Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 94 (tripping or trip-free relay), as these devices are tripping relays that respond to the trip signal of the protective relay that processed the signals from the current and voltage-sensing devices.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.6.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

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.

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 a SPS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES unit within the Balancing Authority Area where the Automatic Reclosing is applied.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of "Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)"?

Reverse power relays are often installed to detect situations where the transmission source becomes deenergized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not 'installed for the purpose of detecting' these faults.

Is a Sudden Pressure Relay an auxiliary tripping relay?

No. IEEE C37.2-2008 assigns the Device No. 94 to auxiliary tripping relays. Sudden pressure relays are assigned Device No. 63. Sudden pressure relays are presently excluded from the standard because it does not utilize voltage and/or current measurements to determine anomalies. Devices that use anything other than electrical detection means are excluded. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

My mechanical device does not operate electrically and does not have calibration settings; what maintenance activities apply?

You must conduct a test(s) to verify the integrity of any trip circuit that is a part of a Protection System. This standard does not cover circuit breaker maintenance or transformer

maintenance. The standard also does not presently cover testing of devices, such as sudden pressure relays (63), temperature relays (49), and other relays which respond to mechanical parameters, rather than electrical parameters. There is an expectation that Fault pressure relays and other non-electrically initiated devices may become part of some maintenance standard. This standard presently covers trip paths. It might seem incongruous to test a trip path without a present requirement to test the device; and, thus, be arguably more work for nothing. But one simple test to verify the integrity of such a trip path could be (but is not limited to) a voltage presence test, as a dc voltage monitor might do if it were installed monitoring that same circuit.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: “A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.”

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: “A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.”

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-

based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft 86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing –

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay .

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action or a Protection System Misoperation attributed to hardware

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

4.1 Frequently Asked Questions:

Why does PRC-005-3 not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-3 requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the “Tables”), and the various components of the definition established for a “Protection System Maintenance Program,” PRC-005-3 establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by “restore” in the definition of maintenance.

The description of “restore” in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity “shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.” Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by “...demonstrate efforts to correct an Unresolved Maintenance Issue...”; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and

management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase “demonstrate efforts to correct” (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a “closed-end process”). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System and Automatic Reclosing Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System and Automatic Reclosing Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers’ recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.
- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term “Condition-Based-Maintenance” (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the “monitored-basis-time-intervals” existing within the standard, the

explanatory discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

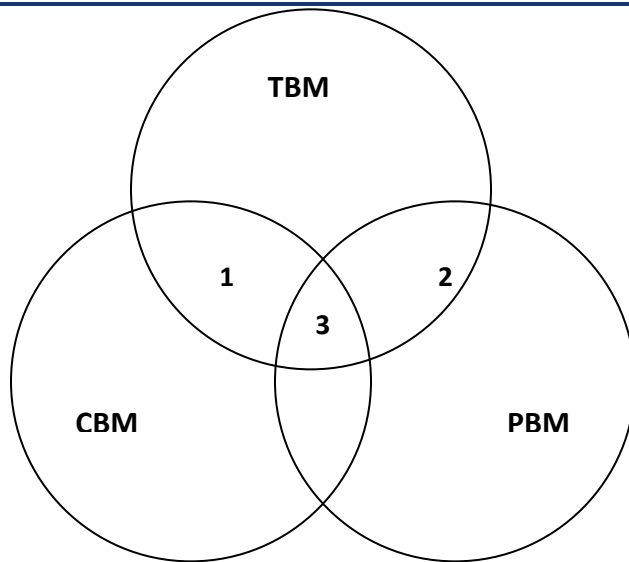
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



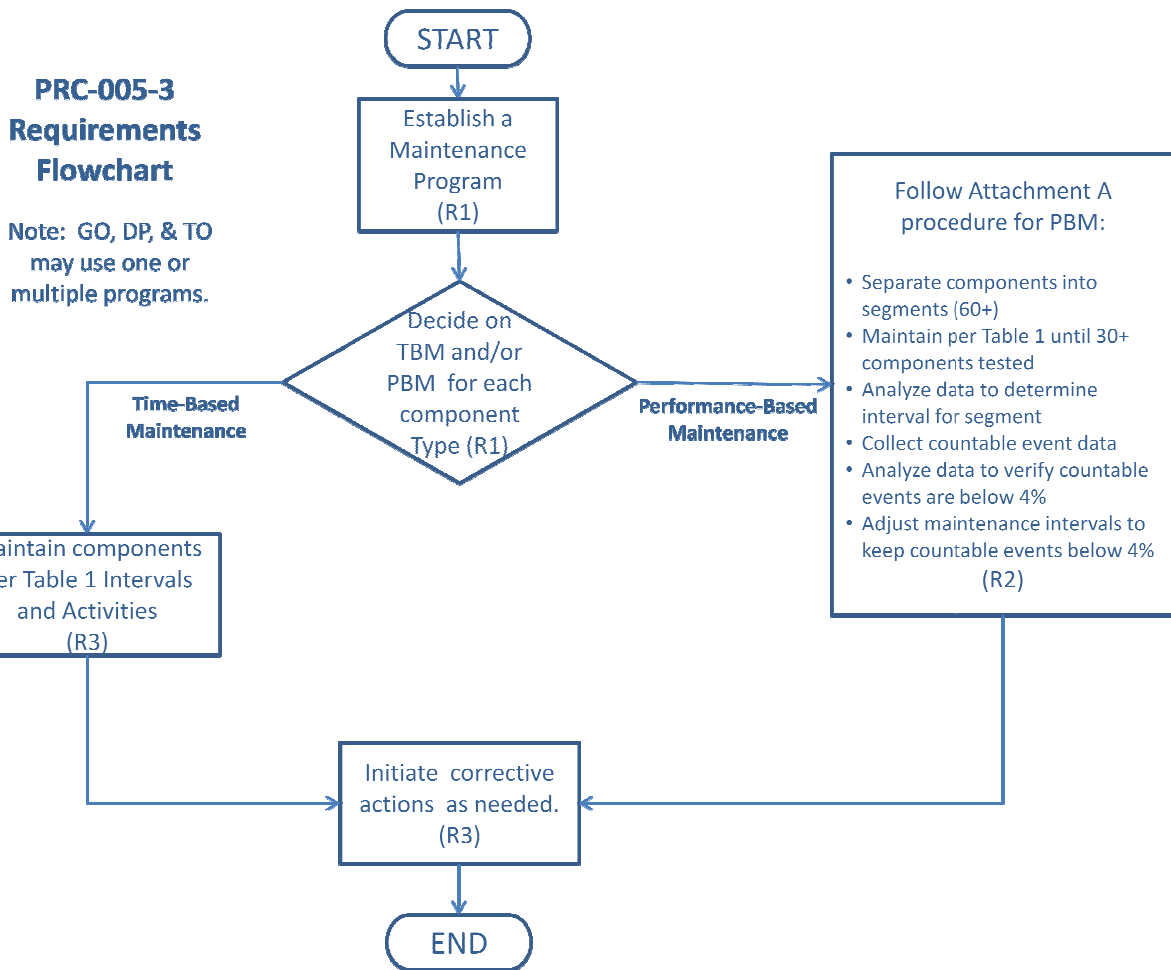
Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to **ONLY** perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a “flow chart” of the standard.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer’s high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

-
- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
 - Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

Excessive maintenance can actually decrease the reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.4) of the standard, is it necessary to

provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

“All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center.”

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

“Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability.”

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a combination of time-based and condition-based maintenance. The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-3. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-3.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a "One Calendar Year Interval," the next event would have to occur on or before December 31, 2010.

Please provide an example of "4 Calendar Months".

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May)

would still be due four months later therefore the activity is due again July. Basically every “four Calendar Months” means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions' section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

-
- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- 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 as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

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- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
 - Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Special Protection System. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, and Table 4 in the standard specify maximum allowable verification intervals for various generations of Protection Systems and Automatic Reclosing and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in [Figures 1](#) and [2](#) at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. [Figure 2](#) shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and SPS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-3:

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- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
 - Table 1-1 is for protective relays,
 - Table 1-2 is for the associated communications systems,
 - Table 1-3 is for current and voltage sensing devices,
 - Table 1-4 is for station dc supply and
 - Table 1-5 is for control circuits.
 - Table 2, is for alarms; this was broken out to simplify the other tables.
 - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
 - Table 4 is for Automatic Reclosing.
 - Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
 - This Maintenance activity is the minimum maintenance activity that must be documented.
 - If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
 - After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
 - If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
 - Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
 - An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows

maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-3. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-3, most notable of which is an entity using performance based maintenance methodology. If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc, are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.
2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.
3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or SPS (as opposed to a monitoring task) must be verified as a component in a Protection System.
4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-3 for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-3 is a more economical approach while addressing the reliability requirements of the BES.
5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform

properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).
7. “End-to-end test,” as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.
8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.
9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states “...settings are as specified.”

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require “...that the relay settings be correct...” because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have “drifted” since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the “Verify that settings are as specified” maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about SPS interfaces between different entities or owners?

As in all of the Protection System requirements, SPS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Special Protection System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the SPS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for SPS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an SPS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an SPS scheme should that occur. Forced trip tests of circuit breakers (etc) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unnecessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval, then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays

-
- Neutral overcurrent relay
 - Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team’s intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that “affects the tripping” of the breaker is included in the scope of I/O of the relay to be verified. By “affects the tripping,” one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be “picked up” or “turned on and off” and verified as changing state by the microprocessor of the relay. Each output should be “operated” or “closed and opened” from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to “jumper” the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A

distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-3 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or to the previous scheduled (on-site) audit date, whichever is longer.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please use a specific example to demonstrate the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld. For example: “Company A” has a maintenance plan that requires its electromechanical protective relays be tested every three calendar years, with a maximum allowed grace period of an additional 18 months. This entity would be required to maintain its records of maintenance of its last two routine scheduled tests. Thus, its test records would have a latest routine test, as well as its previous routine test. The interval between tests is, therefore, provable to an auditor as being within “Company A’s” stated maximum time interval of 4.5 years.

The intent is not to require three test results proving two time intervals, but rather have two test results proving the last interval. The drafting team contends that this minimizes storage requirements, while still having minimum data available to demonstrate compliance with time intervals.

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-3, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-3 assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-3 requires performance of maintenance activities that are deemed necessary to detect and correct plausible age and service related degradation of components, such that a properly built and commission tested Protection System will continue to function as designed over its service life.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-3 would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the “Calendar Year” language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a "grace period" without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for “time-interval extensions” or “grace periods” to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. “Maximum time intervals” by their very term negates any “time-interval extension” or “grace periods.” To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was “...no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years...” The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table’s use of the term “Calendar” in the column for “Maximum Maintenance Interval.” The PSMT SDT deemed it necessary to include the term “Calendar” to

facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term “Calendar” to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity’s use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as *ISO 9001-2000, Quality Management Systems – Requirements*; or applicable parts of the NIST Baldrige National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is “the sampling distribution of the sample mean can be approximated by a normal probability distribution.” The Central Limit Theorem states: “In selecting simple random samples of size n from a population, the sampling distribution of the sample mean \bar{x} can be approximated by a normal probability distribution as the sample size becomes large.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

“... whenever we are using a large simple random sample (rule of thumb: $n \geq 30$), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

“If samples of size n , when $n \geq 30$, are drawn from any population with a mean μ and a standard deviation σ , the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation.” (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)

“The sample size is large (generally $n \geq 30$)... (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)

“... the normal is often used as an approximation to the t distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection.” (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a “Pass/Fail” format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z \sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1 - \pi) \left(\frac{z}{B} \right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.96 \text{ (This equates to a 95\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=59.0$.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.44 \text{ (85\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=31.8$.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design

errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing “86” lock-out relays (LOR). “Entity A” has two types of LOR’s type “X” and type “Y”; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type “X” failures, but human error led to tripping a BES Element 100 times; they find 100 type “Y” failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead “Entity A” to change time intervals. Type “X” LOR can be placed into extended time interval testing because of its low failure rate (zero failures) while Type “Y” would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment performance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, “reset the clock” on everything you’ve done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that “resetting the clock” should not be construed as interfering with an entity’s routine testing schedule because the “clock-reset” would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that “replaced relay” will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. $6/200 = 3\%$ failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. $6/100 = 6\%$ failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year ($1000/8$). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. $6/125 = 5\%$ failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year ($1000/7$). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. $6/143 = 4.2\%$ failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year ($1000/6$). After a year, they again find six

failures out of the 167 units tested. $6/167 = 3.6\%$ failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures “Control Circuitry” as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity’s specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device

that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year ($1000/12$). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures “voltage and current inputs to the protective relays” as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a “Relay Scheme.” Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT’s or specific PT’s. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 2000 “Relay Schemes,” all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT’s. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity’s relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their “Voltage and Current Sensing” population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested ($U = P/I$)	# of Failures Found (F)	Failure Rate ($=F/U$)	Decision to Change Interval Yes or No	Interval Chose
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2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays “that are designed to provide protection for the BES,” this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its

regularly scheduled cycle. (However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays "out-of-service". What are our responsibilities when it comes to "out-of-service" devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-3 are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-3. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-3 to remove such component(s). Obviously, prudence would dictate that an “out-of-service” device is truly made inactive. There are no record requirements listed in PRC-005-3 for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-3 requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-3 requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

“R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.”

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state “...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues...” The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-3 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

These relays are defined as the devices that receive the input signal from the current and voltage sensing devices and are used to isolate a Faulted Element of the BES. Devices that sense thermal, vibration, seismic, pressure, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
 - There is no specific protective relay commissioning test or relay routine test mandated.
 - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the

protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and vars around the entire bus; this should add up to zero watts and zero vars, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "...verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ..." Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay

and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor-based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately “verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ...” while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "...designed to provide protection for the BES..." then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

While relays that do not respond to electrical quantities are presently excluded from this standard, their control circuits are included if the relay is installed to detect Faults on BES Elements. Thus, the control circuit of a BES transformer sudden pressure relay should be verified every 12 years, assuming its integrity is not monitored. While a sudden pressure relay control circuit is included within the scope of PRC-005-2, other alarming relay control circuits, (i.e., SF-6 low gas) are not included, even though they may trip the breaker being monitored.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes

that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-3 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-3 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-3 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.

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- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-3 applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have an non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- 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.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, “station batteries” are replaced with “station dc supply” to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-3 is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by "continuity" of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.

- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the

station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example “Conductance Readings” from one manufacturer’s test equipment do not correlate to “Impedance Readings” from a different manufacturer’s test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity

readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries).

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery

containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance “as designed” vs. battery performance “as manufactured.” The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer’s rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trendline against the established baseline. The type of probe and its location (post, connector, etc) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measurable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be “forming” after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an "adequate" ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one

minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-3 is there a maintenance activity to inspect the structural integrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.

Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the "Unintentional dc Grounds" requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a "check-off" of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to "all cells," is it sufficient to have a documentation method that refers to "all cells," or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-3 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980's several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery's current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The

inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "...depending on the degree of change a performance test, cell replacement or other corrective action may be necessary..." (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or

above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid 1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically

trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to “measure battery cell/unit internal ohmic values.” Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is “...verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline.” This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to “Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.”

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to ‘perform as manufactured.’ It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the “perform as manufactured six-month test” at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the “thermal runaway test” at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float

(charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to “verify station dc supply voltage” every “4 calendar months” (see table 1-4(a)), the owner can install a monitoring and alarming device “with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure” and “no periodic verification of station dc supply voltage is required” (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install “electrolyte level monitoring and alarming in every cell” and “unintentional dc ground monitoring and alarming” (see second and third rows of table 1-4(f)), the owner will have to “inspect electrolyte level and for unintentional grounds” every “4 calendar months” (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to “Protection System Control Circuitry”, rather than those portions of the table applicable to communications equipment.

What is meant by "Channel" and "Communications Systems" in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the “channel” as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting "performance criteria." What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These

limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe “form-b” contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "...does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature autoreclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervisor/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage

supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that is not part of an SPS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that is part of an SPS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the SPS, and must be verified.

15.9 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.9.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics

-
- Maintenance records
 - Logs (operator, substation, and other types of log)
 - Inspection forms
 - Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
 - Check-off forms (paper or electronic)
 - Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 ("Special Protection System Misoperation"). Can I also use it to show compliance for this Standard, PRC-005-3?

Maintaining evidence for operation of Special Protection Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-3.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

References

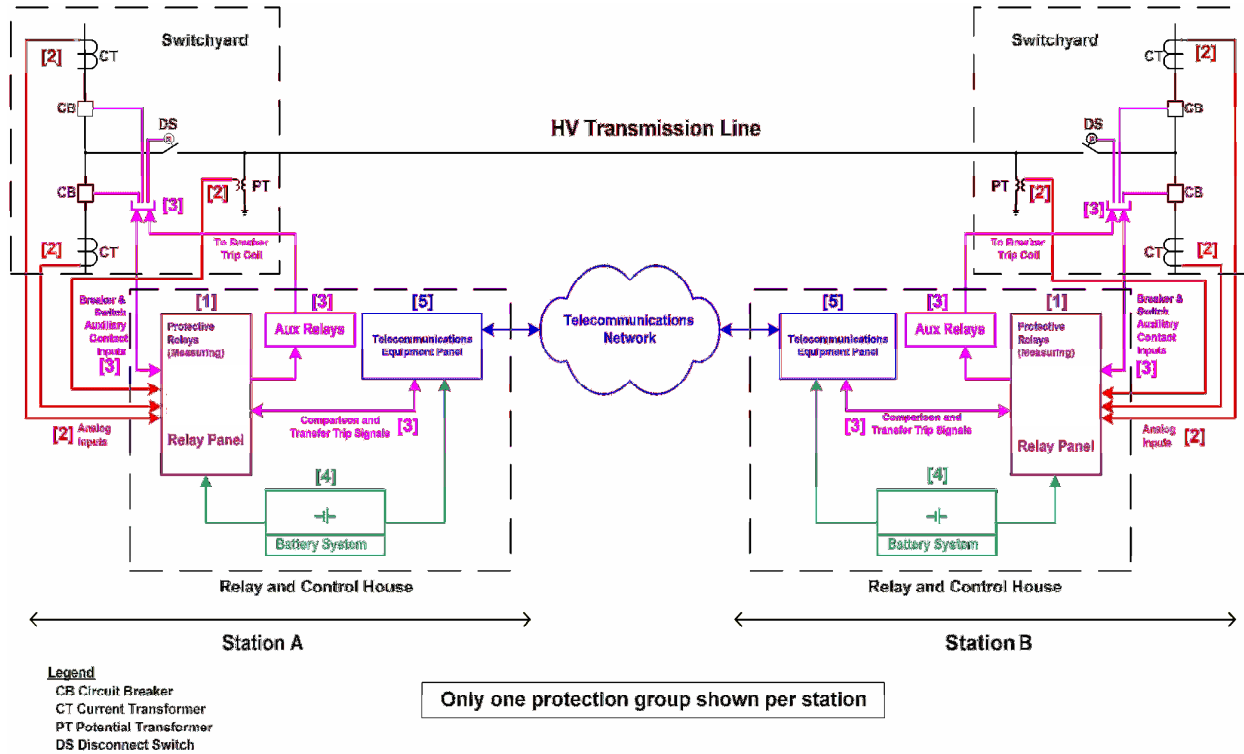
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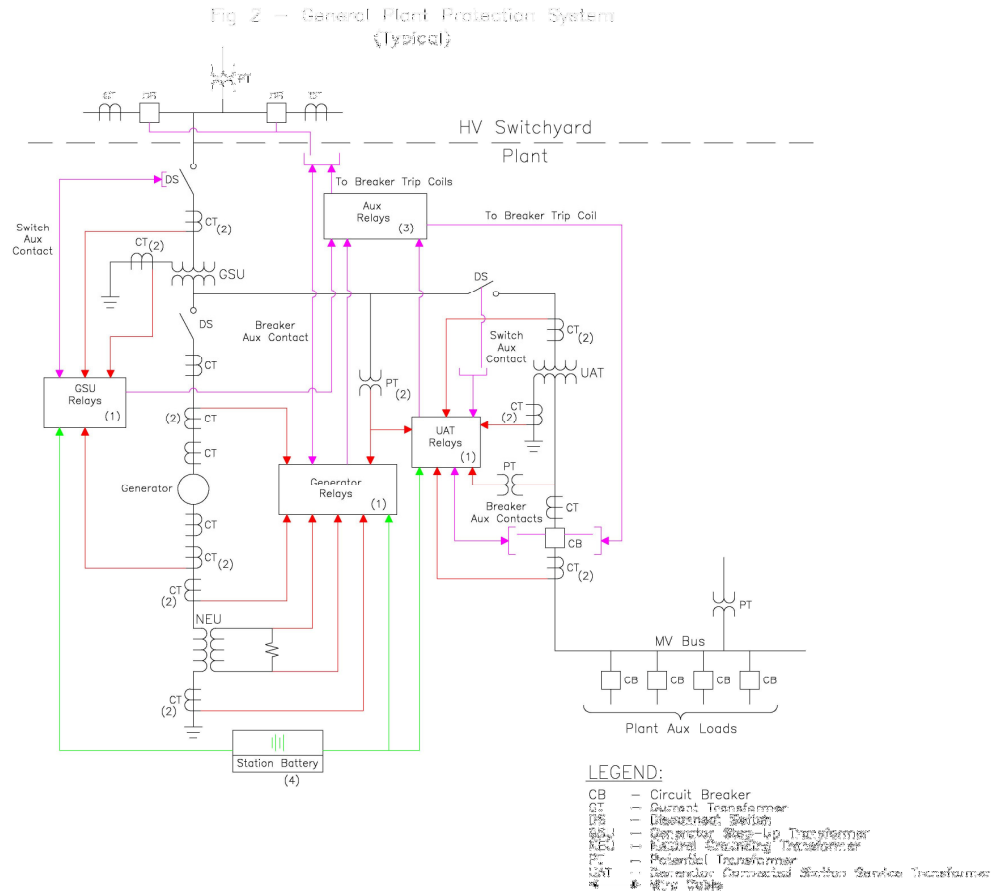
Figures

Figure 1: Typical Transmission System



For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 1 & 2 Legend – Components of Protection Systems

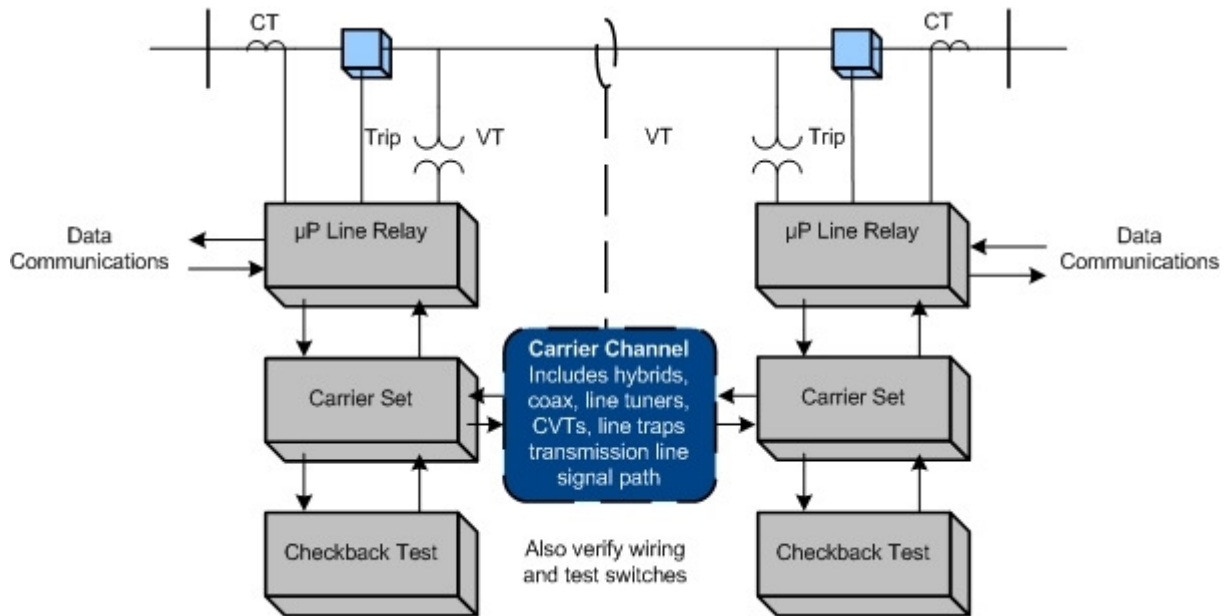
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

[Additional information can be found in References](#)

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line faults, and to avoid over-tripping for faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



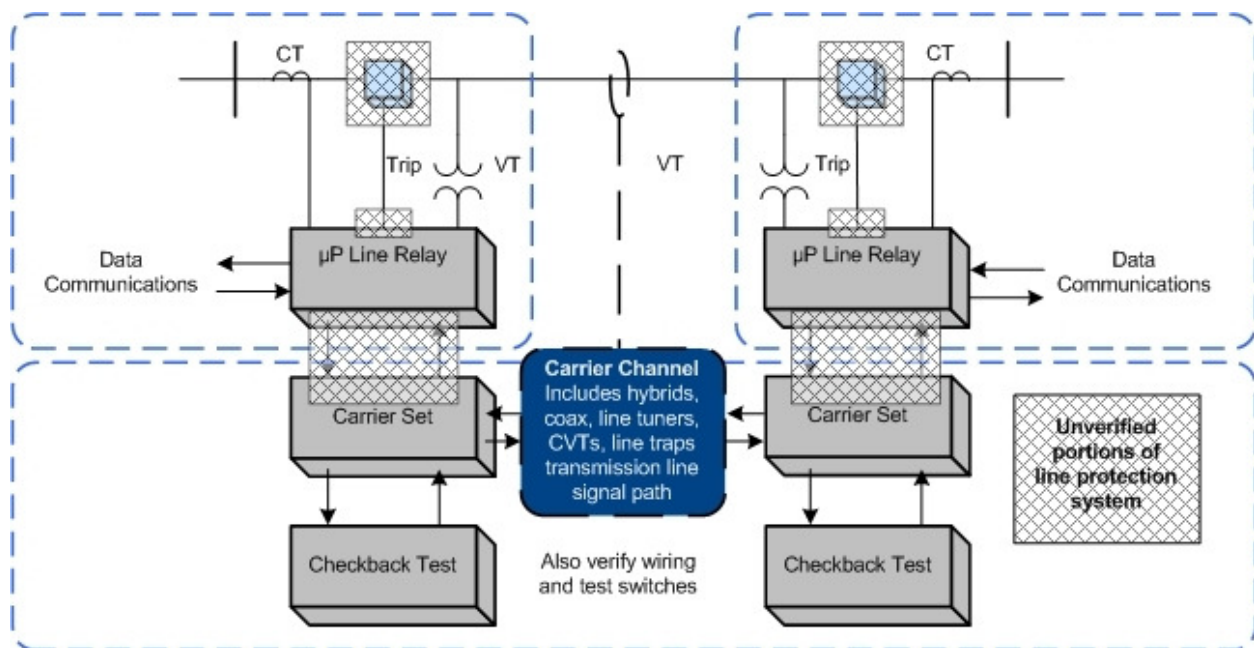
In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.
2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the

contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.

3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-3 does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

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Supplementary Reference and FAQ

PRC-005-3 Protection System Maintenance

~~April~~ July 2013

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1. Introduction and Summary

Note: This supplementary reference for PRC-005-3 is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. [PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.](#)

[FERC Order 758 further directed that maintenance of reclosing relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive, and, when approved, will supersede PRC-005-2.](#)

[This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3.](#)

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-3 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the [NERC Glossary of Terms](#) used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- 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.

2.3 Applicability of New Protection System Maintenance Standards

The BES purpose is to transfer bulk power. The applicability language has been changed from the original PRC-005:

“...affecting the reliability of the Bulk Electric System (BES)...”

To the present language:

“...that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).”

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution

Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

NERC's approved definition of Bulk Electric System is:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.

The BES definition is presently undergoing the process of revision.

Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a [June 14, 2007 Informational Filing](#).

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Special Protection Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 94 (tripping or trip-free relay), as these devices are tripping relays that respond to the trip signal of the protective relay that processed the signals from the current and voltage-sensing devices.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.6.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

4.2.6.1 Automatic Reclosing applied on the terminals of BES Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 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 a SPS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES unit within the Balancing Authority Area where the Automatic Reclosing is applied.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when inadvertent-premature autoreclosing near a generating station subjects the generation station to severe fault stresseshas the potential to cause generating unit or plant instability. A technical report, “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of "Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)"?

Reverse power relays are often installed to detect situations where the transmission source becomes deenergized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not ‘installed for the purpose of detecting’ these faults.

Is a Sudden Pressure Relay an auxiliary tripping relay?

No. IEEE C37.2-2008 assigns the Device No. 94 to auxiliary tripping relays. Sudden pressure relays are assigned Device No. 63. Sudden pressure relays are presently excluded from the standard because it does not utilize voltage and/or current measurements to determine anomalies. Devices that use anything other than electrical detection means are excluded. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

My mechanical device does not operate electrically and does not have calibration settings; what maintenance activities apply?

You must conduct a test(s) to verify the integrity of any trip circuit that is a part of a Protection System. This standard does not cover circuit breaker maintenance or transformer maintenance. The standard also does not presently cover testing of devices, such as sudden pressure relays (63), temperature relays (49), and other relays which respond to mechanical parameters, rather than electrical parameters. There is an expectation that Fault pressure relays and other non-electrically initiated devices may become part of some maintenance standard. This standard presently covers trip paths. It might seem incongruous to test a trip path without a present requirement to test the device; and, thus, be arguably more work for nothing. But one simple test to verify the integrity of such a trip path could be (but is not limited to) a voltage presence test, as a dc voltage monitor might do if it were installed monitoring that same circuit.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: “A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.”

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: “A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.”

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-

based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft 86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System and ~~Automatic-automatic Reclosing-reclosing Components-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 — Detect visible signs of component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing –

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay ~~through the close coil(s) of the circuit breakers or similar device but excluding breaker internal controls such as anti-pump and various interlock circuits.~~

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~~Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

4.1 Frequently Asked Questions:

Why does PRC-005-3 not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-3 requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the “Tables”), and the various components of the definition established for a “Protection System Maintenance Program,” PRC-005-3 establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by “restore” in the definition of maintenance.

The description of “restore” in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity “shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.” Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by “...demonstrate efforts to correct an Unresolved Maintenance Issue...”; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase “demonstrate efforts to correct” (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a “closed-end process”). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System and Automatic Reclosing Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System and Automatic Reclosing Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers’ recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.
- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term “Condition-Based-Maintenance” (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the “monitored-basis-time-intervals” existing within the standard, the

explanatory discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

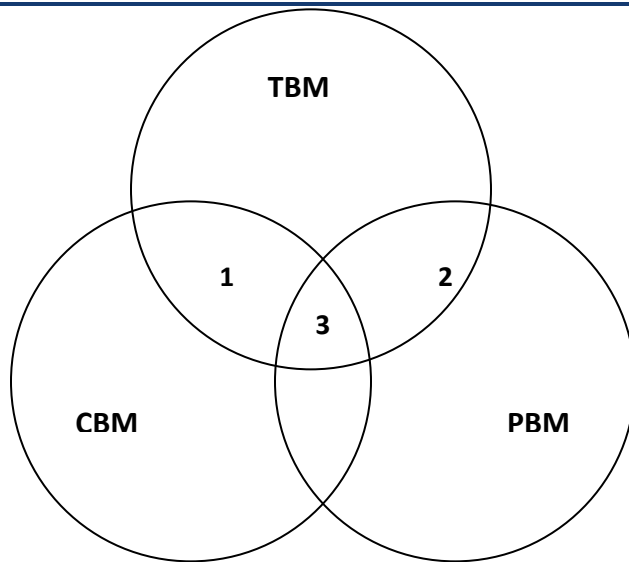
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



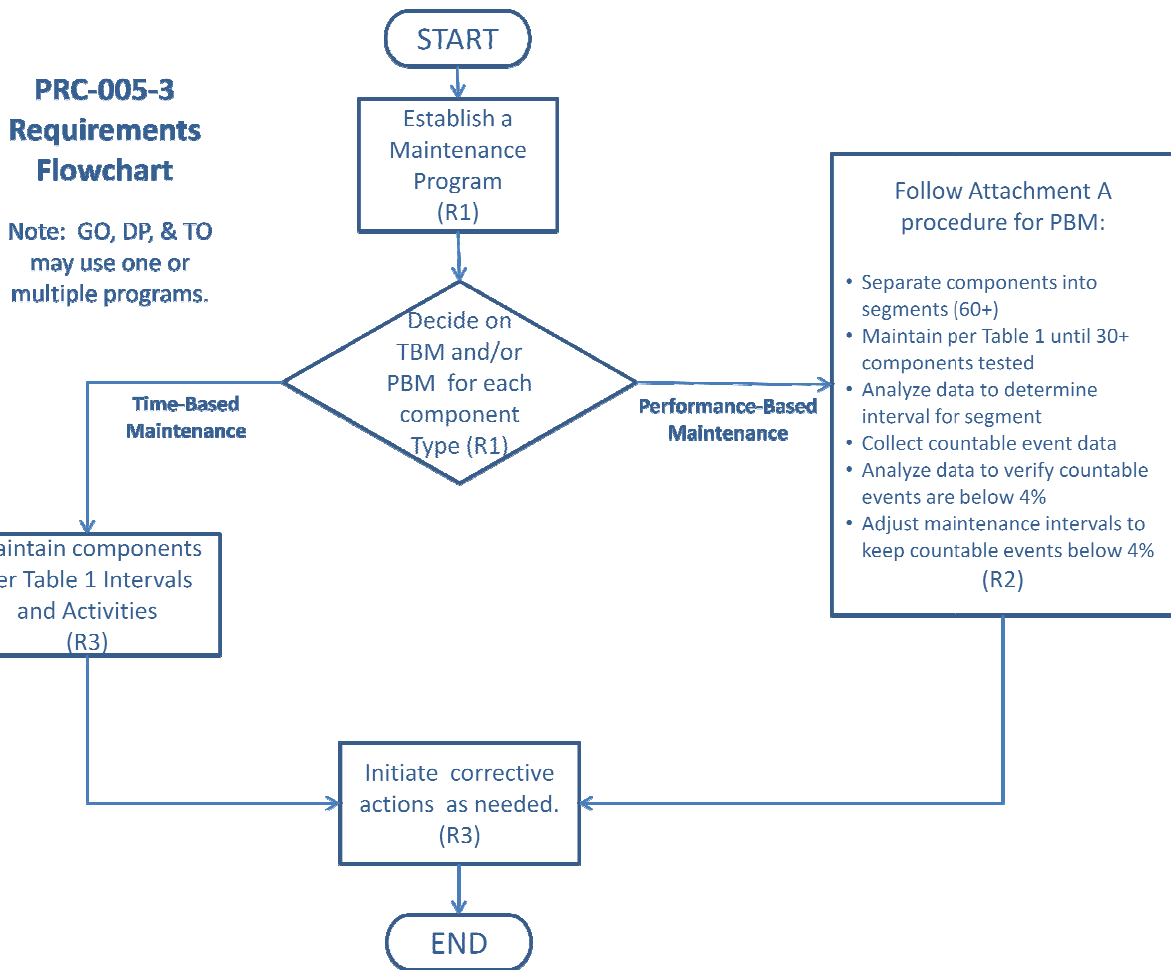
Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to **ONLY** perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a “flow chart” of the standard.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer’s high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

-
- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
 - Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

Excessive maintenance can actually decrease the reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.4) of the standard, is it necessary to

provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

“All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center.”

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

“Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability.”

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a combination of time-based and condition-based maintenance. The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-3. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-3.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a "One Calendar Year Interval," the next event would have to occur on or before December 31, 2010.

Please provide an example of "4 Calendar Months".

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number 5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May)

would still be due four months later therefore the activity is due again July. Basically every “four Calendar Months” means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions' section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

-
- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- 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 as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

-
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
 - Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Special Protection System. It may be a breaker, valve, distributed control system, or any variety of other devices. [This response may include tripping, closing, or other control actions.](#)

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, and Table 4 in the standard specify maximum allowable verification intervals for various generations of Protection Systems and Automatic Reclosing and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in [Figures 1](#) and [2](#) at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. [Figure 2](#) shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and SPS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-3:

-
- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
 - Table 1-1 is for protective relays,
 - Table 1-2 is for the associated communications systems,
 - Table 1-3 is for current and voltage sensing devices,
 - Table 1-4 is for station dc supply and
 - Table 1-5 is for control circuits.
 - Table 2, is for alarms; this was broken out to simplify the other tables.
 - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
 - Table 4 is for Automatic Reclosing.
 - Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
 - This Maintenance activity is the minimum maintenance activity that must be documented.
 - If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
 - After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
 - If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
 - Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
 - An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows

maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-3. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-3, most notable of which is an entity using performance based maintenance methodology. If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc, are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.
2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.
3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or SPS (as opposed to a monitoring task) must be verified as a component in a Protection System.
4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-3 for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-3 is a more economical approach while addressing the reliability requirements of the BES.
5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform

properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).
7. “End-to-end test,” as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.
8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.
9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states “...settings are as specified.”

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require “...that the relay settings be correct...” because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have “drifted” since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the “Verify that settings are as specified” maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about SPS interfaces between different entities or owners?

As in all of the Protection System requirements, SPS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Special Protection System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the SPS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for SPS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an SPS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an SPS scheme should that occur. Forced trip tests of circuit breakers (etc) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unnecessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval, then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays

-
- Neutral overcurrent relay
 - Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A

distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-3 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or to the previous scheduled (on-site) audit date, whichever is longer.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please use a specific example to demonstrate the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld. For example: “Company A” has a maintenance plan that requires its electromechanical protective relays be tested every three calendar years, with a maximum allowed grace period of an additional 18 months. This entity would be required to maintain its records of maintenance of its last two routine scheduled tests. Thus, its test records would have a latest routine test, as well as its previous routine test. The interval between tests is, therefore, provable to an auditor as being within “Company A’s” stated maximum time interval of 4.5 years.

The intent is not to require three test results proving two time intervals, but rather have two test results proving the last interval. The drafting team contends that this minimizes storage requirements, while still having minimum data available to demonstrate compliance with time intervals.

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-3, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-3 assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-3 requires performance of maintenance activities that are deemed necessary to detect and correct plausible age and service related degradation of components, such that a properly built and commission tested Protection System will continue to function as designed over its service life.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-3 would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the “Calendar Year” language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a "grace period" without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original Protection System Maintenance – A Technical Reference in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for “time-interval extensions” or “grace periods” to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. “Maximum time intervals” by their very term negates any “time-interval extension” or “grace periods.” To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was “...no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years...” The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table’s use of the term “Calendar” in the column for “Maximum Maintenance Interval.” The PSMT SDT deemed it necessary to include the term “Calendar” to

facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term “Calendar” to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity’s use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as *ISO 9001-2000, Quality Management Systems – Requirements*; or applicable parts of the NIST Baldrige National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is “the sampling distribution of the sample mean can be approximated by a normal probability distribution.” The Central Limit Theorem states: “In selecting simple random samples of size n from a population, the sampling distribution of the sample mean \bar{x} can be approximated by a normal probability distribution as the sample size becomes large.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

“... whenever we are using a large simple random sample (rule of thumb: $n \geq 30$), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

“If samples of size n , when $n \geq 30$, are drawn from any population with a mean μ and a standard deviation σ , the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation.” (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)

“The sample size is large (generally $n \geq 30$)... (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)

“... the normal is often used as an approximation to the t distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection.” (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a “Pass/Fail” format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z \sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1 - \pi) \left(\frac{z}{B} \right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.96 \text{ (This equates to a 95\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=59.0$.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.44 \text{ (85\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=31.8$.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design

errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing “86” lock-out relays (LOR). “Entity A” has two types of LOR’s type “X” and type “Y”; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type “X” failures, but human error led to tripping a BES Element 100 times; they find 100 type “Y” failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead “Entity A” to change time intervals. Type “X” LOR can be placed into extended time interval testing because of its low failure rate (zero failures) while Type “Y” would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment performance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, “reset the clock” on everything you’ve done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that “resetting the clock” should not be construed as interfering with an entity’s routine testing schedule because the “clock-reset” would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that “replaced relay” will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. $6/200 = 3\%$ failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. $6/100 = 6\%$ failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year ($1000/8$). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. $6/125 = 5\%$ failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year ($1000/7$). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. $6/143 = 4.2\%$ failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year ($1000/6$). After a year, they again find six

failures out of the 167 units tested. $6/167 = 3.6\%$ failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures “Control Circuitry” as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity’s specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device

that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year ($1000/12$). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures “voltage and current inputs to the protective relays” as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a “Relay Scheme.” Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT’s or specific PT’s. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 2000 “Relay Schemes,” all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT’s. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity’s relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their “Voltage and Current Sensing” population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
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2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays “that are designed to provide protection for the BES,” this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its

regularly scheduled cycle. (However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays "out-of-service". What are our responsibilities when it comes to "out-of-service" devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-3 are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-3. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-3 to remove such component(s). Obviously, prudence would dictate that an “out-of-service” device is truly made inactive. There are no record requirements listed in PRC-005-3 for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-3 requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-3 requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

“R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.”

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state “...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues...” The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-3 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

These relays are defined as the devices that receive the input signal from the current and voltage sensing devices and are used to isolate a Faulted Element of the BES. Devices that sense thermal, vibration, seismic, pressure, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
 - There is no specific protective relay commissioning test or relay routine test mandated.
 - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the

protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and vars around the entire bus; this should add up to zero watts and zero vars, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "...verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ..." Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay

and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor-based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately “verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ...” while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "...designed to provide protection for the BES..." then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

While relays that do not respond to electrical quantities are presently excluded from this standard, their control circuits are included if the relay is installed to detect Faults on BES Elements. Thus, the control circuit of a BES transformer sudden pressure relay should be verified every 12 years, assuming its integrity is not monitored. While a sudden pressure relay control circuit is included within the scope of PRC-005-2, other alarming relay control circuits, (i.e., SF-6 low gas) are not included, even though they may trip the breaker being monitored.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes

that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-3 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-3 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-3 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.

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- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-3 applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have an non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- 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.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, “station batteries” are replaced with “station dc supply” to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-3 is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by "continuity" of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.

- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the

station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example “Conductance Readings” from one manufacturer’s test equipment do not correlate to “Impedance Readings” from a different manufacturer’s test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity

readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries).

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery

containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance “as designed” vs. battery performance “as manufactured.” The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer’s rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trendline against the established baseline. The type of probe and its location (post, connector, etc) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measurable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be “forming” after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an "adequate" ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one

minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-3 is there a maintenance activity to inspect the structural integrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.

Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the "Unintentional dc Grounds" requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a "check-off" of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to "all cells," is it sufficient to have a documentation method that refers to "all cells," or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-3 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980's several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery's current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The

inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "...depending on the degree of change a performance test, cell replacement or other corrective action may be necessary..." (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or

above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid 1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically

trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to “measure battery cell/unit internal ohmic values.” Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is “...verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline.” This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to “Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.”

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to ‘perform as manufactured.’ It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the “perform as manufactured six-month test” at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the “thermal runaway test” at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float

(charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to “verify station dc supply voltage” every “4 calendar months” (see table 1-4(a)), the owner can install a monitoring and alarming device “with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure” and “no periodic verification of station dc supply voltage is required” (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install “electrolyte level monitoring and alarming in every cell” and “unintentional dc ground monitoring and alarming” (see second and third rows of table 1-4(f)), the owner will have to “inspect electrolyte level and for unintentional grounds” every “4 calendar months” (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to “Protection System Control Circuitry”, rather than those portions of the table applicable to communications equipment.

What is meant by "Channel" and "Communications Systems" in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the “channel” as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting "performance criteria." What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These

limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe “form-b” contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "...does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, upon initiation, that the reclosing relay does not issue a premature closing command. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature autoreclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervisor/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a premature closing command being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage

supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

None

For Automatic Reclosing that is not part of an SPS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that is part of an SPS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the SPS, and must be verified.

15.9 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. –The evidence can be of many different forms. –The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this ~~Standard~~ standard.

15.9.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)

-
- Database lists, records and/or screen shots that demonstrate compliance information
 - Prints, diagrams and/or schematics
 - Maintenance records
 - Logs (operator, substation, and other types of log)
 - Inspection forms
 - Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
 - Check-off forms (paper or electronic)
 - Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 ("Special Protection System Misoperation"). Can I also use it to show compliance for this Standard, PRC-005-3?

Maintaining evidence for operation of Special Protection Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-3.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

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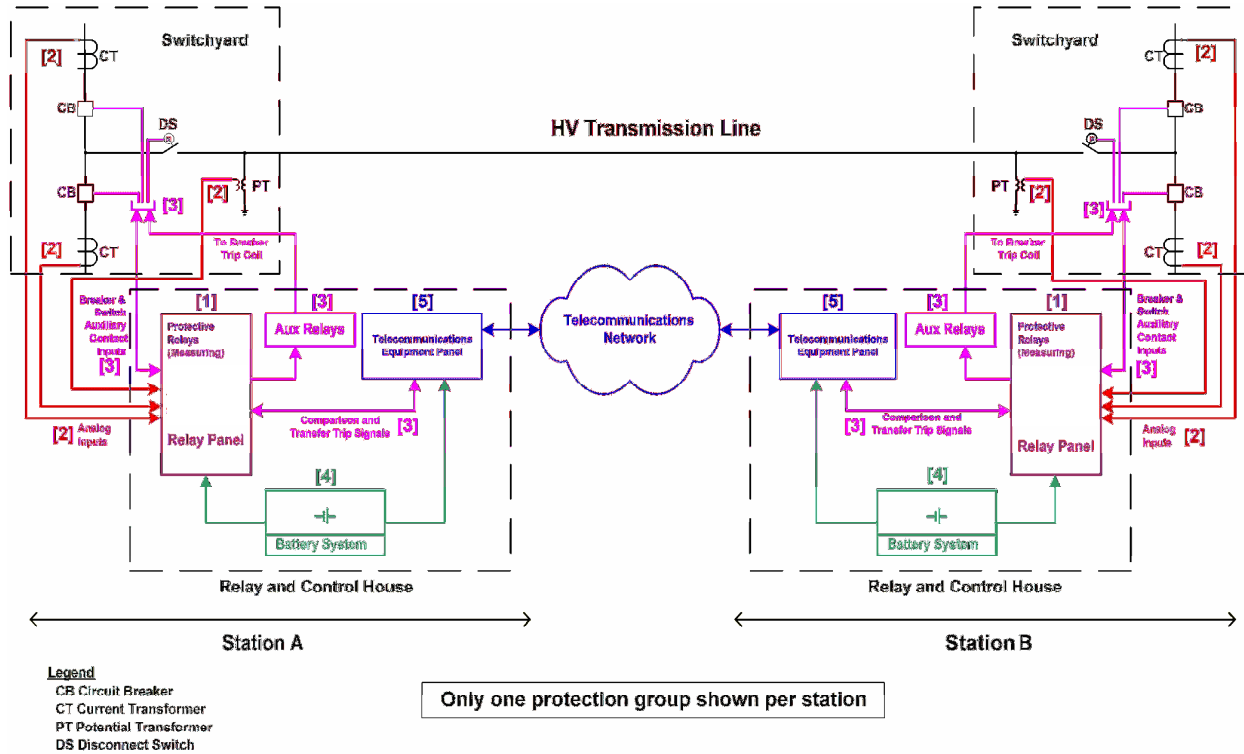
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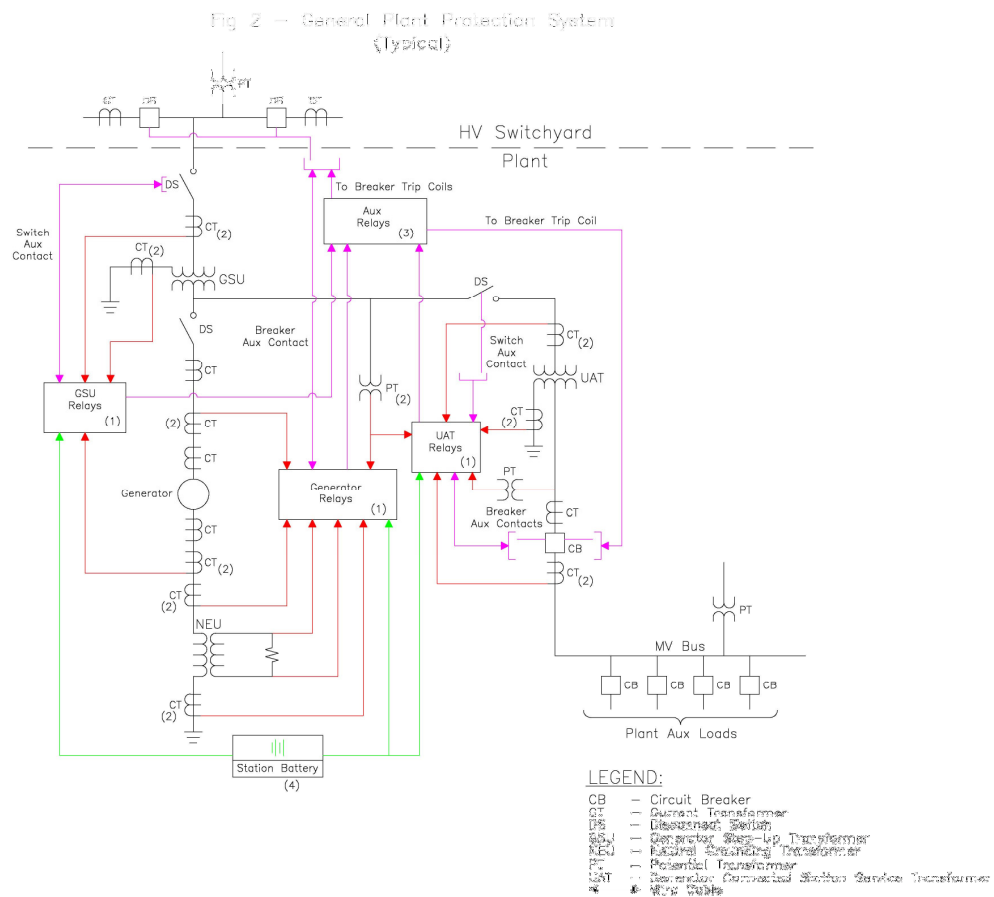
Figures

Figure 1: Typical Transmission System



For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 1 & 2 Legend – Components of Protection Systems

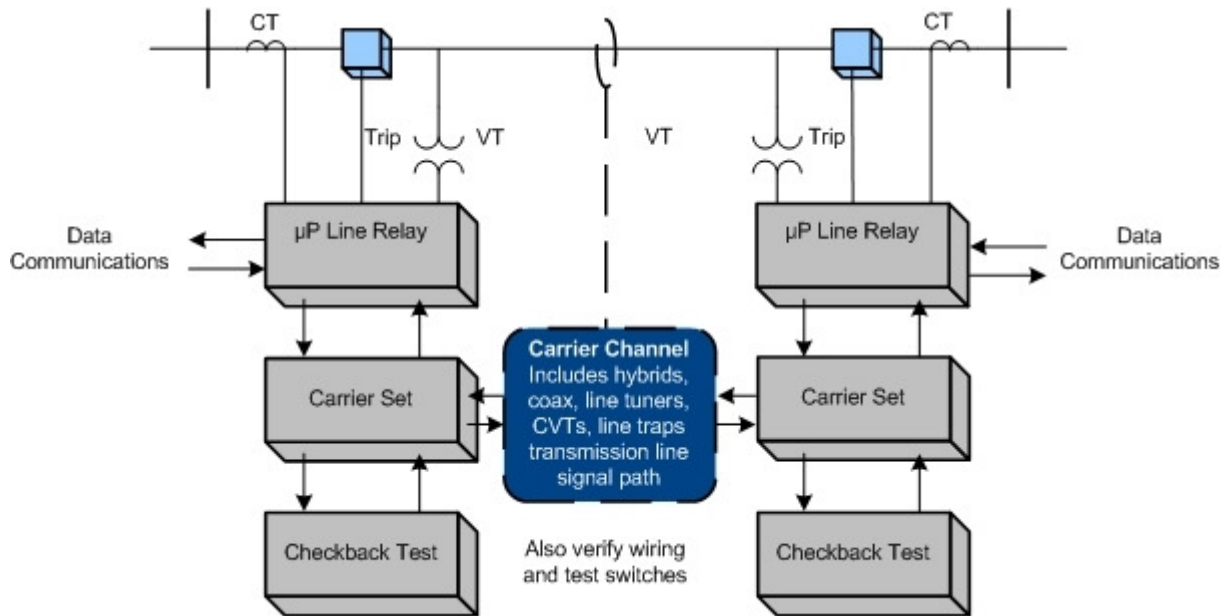
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

[Additional information can be found in References](#)

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line faults, and to avoid over-tripping for faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



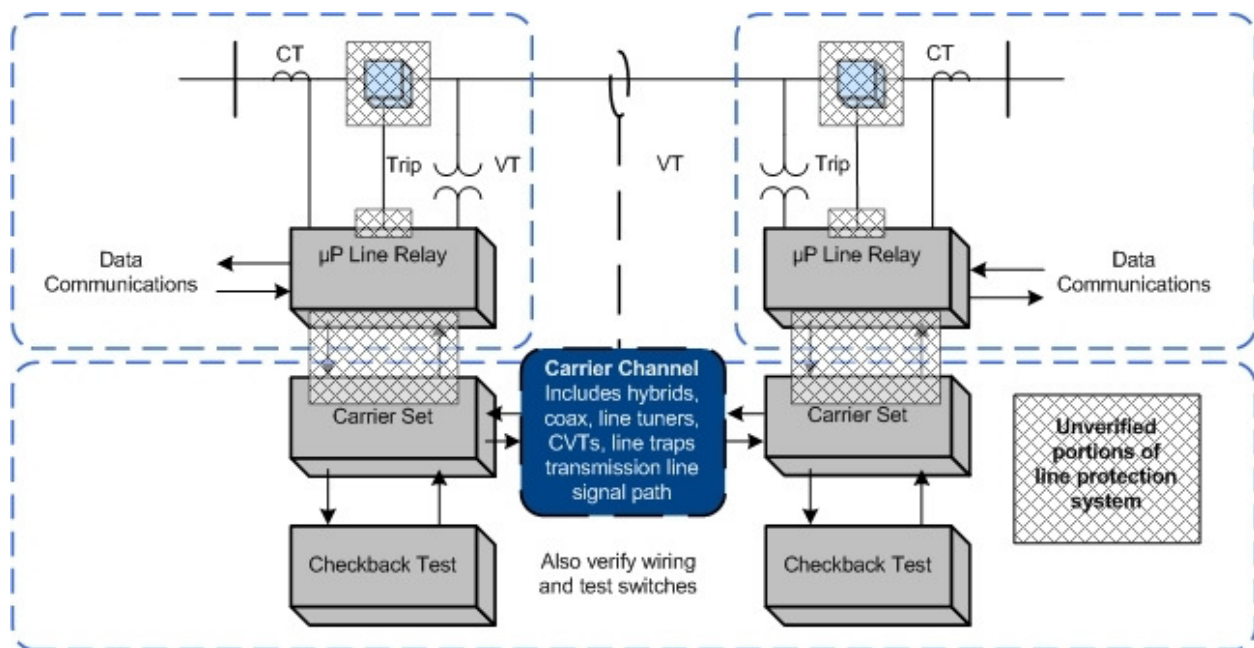
In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.
2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the

contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.

3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-3 does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

Protection System Maintenance Standard Drafting Team

Charles W. Rogers

Chairman

Consumers Energy Co.

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Xcel Energy

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NERC

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Matthew Westrich
American Transmission Company

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ComEd

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ITC Holdings

Kristina Marriott
ENOSERV

Table of Issues and Directives

Project 2007-17.2 PRC-005-3

Protection System and Automatic Reclosing Maintenance

Table of Issues and Directives Associated with PRC-005-3

Source	Directive Language (including pg #)	Disposition	Section and/or Requirement(s)
FERC Order 758	27. We note that the original project to revise Reliability Standard PRC-005 failed a recirculation ballot in July of 2011. The project was subsequently reinitiated to continue the efforts to develop Reliability Standard PRC-005-2. Given that the project to draft proposed revisions to Reliability Standard PRC-005-1 continues in this reinitiated effort, and the importance of maintaining and testing reclosing relays, we direct NERC to include maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System, as discussed above, within these reinitiated efforts to revise Reliability Standard PRC-005.	Specific minimum activities and maximum allowable intervals are included in the draft standard within Table 4.	Applicability 4.2.6 Requirement R1, R3, Requirement R4, Table 4

Standards Announcement

Project 2007-17.2 Protection System Maintenance and Testing Phase 2 (Reclosing Relays) PRC-005-3

Ballot and Non-Binding Poll now open through August 23, 2013

[Now Available](#)

A ballot for **PRC-005-3 – Protection System and Automatic Reclosing Maintenance** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels is open through **8 p.m. Eastern on Friday, August 23, 2013.**

Background information for this project can be found on the [project page](#).

Instructions

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking [here](#).

As a reminder, this ballot is being conducted under the revised Standard Processes Manual, which requires all negative votes to have an associated comment submitted (or an indication of support of another entity's comments). Please see NERC's [announcement](#) regarding the balloting software updates and the [guidance document](#), which explains how to cast your ballot and note if you've made a comment in the online comment form or support another entity's comment.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process

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

*For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.*

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Standards Announcement

Project 2007-17.2 Protection System Maintenance and Testing Phase 2 (Reclosing Relays) PRC-005-3

Formal Comment Period: July 10, 2013 – August 23, 2013
Ballot Pools Forming Now: July 10, 2013 – August 8, 2013

Upcoming:
Ballot and Non-Binding Poll: August 14-23, 2013

[Now Available](#)

A 45-day formal comment period for **PRC-005-3 – Protection System and Automatic Reclosing Maintenance** is open through **8 p.m. Eastern on Friday, August 23, 2013**. A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on **Thursday, August 8, 2013** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

Background information for this project can be found on the [project page](#).

Instructions for Joining Ballot Pool(s)

Ballot pools are being formed for **PRC-005-3 – Protection System and Automatic Reclosing Maintenance** and the associated non-binding polls in this project. Registered Ballot Body members must join the ballot pools to be eligible to vote in the balloting and submittal of an opinion for the non-binding polls of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: [Join Ballot Pool](#)

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

Ballot: bp-2007-17.2_PRC-005-3_in@nerc.com

Non-Binding poll: bp-2007-17.2_PRC-005_NB_in@nerc.com

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Friday, August 23, 2013**. Please use the [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact [Wendy Muller](#). An off-line, unofficial copy of the comment forms are posted on the [project page](#).

Next Steps

A ballot and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined.

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Standards Announcement

Project 2007-17.2 Protection System Maintenance and Testing Phase 2 (Reclosing Relays) PRC-005-3

Ballot and Non-Binding Poll Results

[Now Available](#)

A ballot for **PRC-005-3 – Protection System and Automatic Reclosing Maintenance** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) concluded at **8 p.m. Eastern on Friday, August 23, 2013.**

Voting statistics are listed below, and the [Ballot Results](#) page provides a link to the detailed results for the ballot.

Approval	Non-binding Poll Results
Quorum: 78.33%	Quorum: 77.45%
Approval: 79.24%	Supportive Opinions: 81.37%

Background information for this project can be found on the [project page](#).

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process

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

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User Name

Password

Log in

Register

- Ballot Pools
- Current Ballots
- Ballot Results
- Registered Ballot Body
- Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2007-17.2 PRC-005-3 August 2013
Ballot Period:	8/14/2013 - 8/26/2013
Ballot Type:	Initial
Total # Votes:	318
Total Ballot Pool:	406
Quorum:	78.33 % The Quorum has been reached
Weighted Segment Vote:	79.24 %
Ballot Results:	The Standard has Passed

Summary of Ballot Results										
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Negative Vote without a Comment	Abstain	No Vote	
			# Votes	Fraction	# Votes	Fraction				
1 - Segment 1	107	1	59	0.776	17	0.224	0	8	23	
2 - Segment 2	9	0.4	3	0.3	1	0.1	0	3	2	
3 - Segment 3	95	1	49	0.71	20	0.29	0	5	21	
4 - Segment 4	33	1	19	0.905	2	0.095	0	2	10	
5 - Segment 5	92	1	47	0.701	20	0.299	0	6	19	
6 - Segment 6	53	1	31	0.738	11	0.262	0	3	8	
7 - Segment 7	0	0	0	0	0	0	0	0	0	
8 - Segment 8	6	0.2	2	0.2	0	0	0	0	4	
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1	
10 - Segment 10	9	0.9	8	0.8	1	0.1	0	0	0	
Totals	406	6.6	219	5.23	72	1.37	0	27	88	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz -American Electric Power)

1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	COMMENT RECEIVED
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejano		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)4/5/13 - 5/6/13 Comment Period - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Abstain	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP))
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENT RECEIVED
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Negative	COMMENT RECEIVED
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Seelke - PSEG)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Comments)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		

1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel)
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Abstain	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz)
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Services	Mark Peters	Affirmative	
3	American Public Power Association	Nathan Mitchell		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pepco Holdings Inc & Affiliates)
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	City of Vineland	Kathy Caignon		
3	Cleco Corporation	Michelle A Corley	Negative	COMMENT RECEIVED
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pepco Holdings Inc & Affiliates)
3	Detroit Edison Company	Kent Kujala	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
3	Entergy	Joel T Plessinger		

3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP-Robert Rhodes)
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	Manitowoc Public Utilities	Thomas E Reed		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP))
3	New York Power Authority	David R Rivera		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	

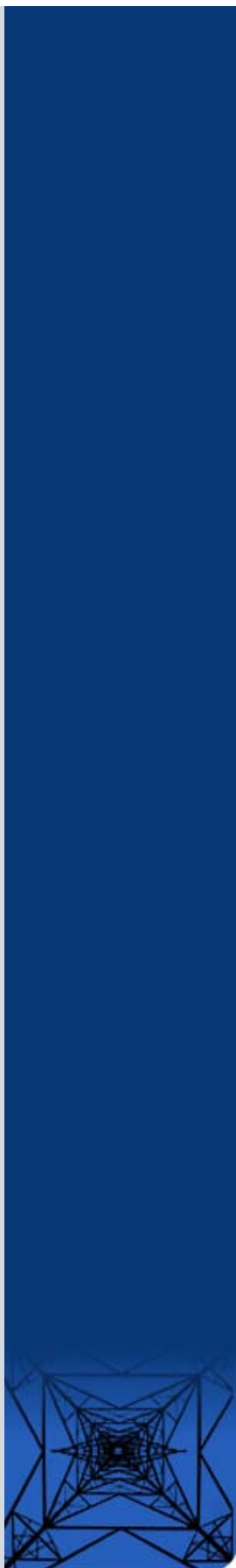
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pepco Holdings Inc & Affiliates)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Seelke on behalf of PSEG Companies)
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	COMMENT RECEIVED
4	Detroit Edison Company	Daniel Herring	Abstain	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrus Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer		
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		

4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Abstain	
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Buckeye Power, Inc.	Paul M Jackson		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	COMMENT RECEIVED
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	El Paso Electric Company	Gustavo Estrada	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	COMMENT RECEIVED
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP _ Robert Rhodes)

5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - 4/5/13 - 5/6/13 Comment Period(Florida Municipal Power Agency) - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Abstain	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Leo Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support comments submitted by Oklahoma Gas & Electric)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	David Ramkalawan	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG comments submitted by John Seelke)
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brown at Essential Power)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	

5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland)
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz American Electric Power)
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Abstain	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	COMMENT RECEIVED
6	Colorado Springs Utilities	Shannon Fair		
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)

6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	COMMENT RECEIVED
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lloyd Linke)
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
8		Edward C Stein	Affirmative	
8		Merle Ashton		
8		Roger C Zaklukiewicz		
8	Foundation for Resilient Societies	William R Harris		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	



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Non-binding Poll

Project 2007-17.2

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-17.2 PRC-005-3 Non-binding Poll
Poll Period:	8/14/2013 - 8/26/2013
Total # Opinions:	285
Total Ballot Pool:	368
Ballot Results:	77.45% of those who registered to participate provided an opinion or an abstention; 81.37% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results				
Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	COMMENT RECEIVED
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		

1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)From 4/5/13 - 5/6/13 Comment Period
1	Florida Power & Light Co.	Mike O'Neil	Abstain	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	

1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz		
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Comments)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		

1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum)
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	COMMENT RECEIVED
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala	Abstain	

3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP- Robert Rhodes)
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	Manitowoc Public Utilities	Thomas E Reed		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS

				- (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	COMMENT RECEIVED

4	Detroit Edison Company	Daniel Herring	Abstain	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrus Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Abstain	
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	COMMENT RECEIVED
5	Cogentrix Energy Power	Mike D Hirst		

	Management, LLC			
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	El Paso Electric Company	Gustavo Estrada	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	COMMENT RECEIVED
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP - Robert Rhodes)
5	Kissimmee Utility Authority	Mike Blough	Abstain	
5	Lakeland Electric	James M Howard	Abstain	
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Abstain	
5	North Carolina Electric Membership	Jeffrey S Brame	Negative	SUPPORTS

	Corp.			THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Leo Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (essential power)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Abstain	

6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Negative	COMMENT RECEIVED
6	Colorado Springs Utilities	Shannon Fair		
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottmangel	Abstain	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lloyd Linke)
8		Edward C Stein	Affirmative	
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (41 Responses)

Name (25 Responses)

Organization (25 Responses)

Group Name (16 Responses)

Lead Contact (16 Responses)

IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (6 Responses)

Comments (41 Responses)

Question 1 (35 Responses)

Question 1 Comments (35 Responses)

Question 2 (31 Responses)

Question 2 Comments (35 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Referencing Applicability Section 4.2.6, the Balancing Authority has to notify and provide documentation to the appropriate entities in 4.2.6.1 and 4.2.6.2 that automatic reclosing maintenance is required. TO substations within 10 circuit miles will need to be identified by the Balancing Authority as well. To clarify Footnote 1 on page 4, suggest the following rewording: Automatic Reclosing as addressed in Sections 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 not cleared for the length of a breaker trip-close-trip operating time does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied. In the Implementation Plan the SDT did a good job inserting the appropriate wording to remove a potential conflict with regulatory practice with respect to the effective date of the standard. However, the wording needs to be inserted in Section 4 of the Background Section. Review the Implementation Plan and insert the following words where appropriate: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” The Implementation Plan must be made available throughout the life of the Standard.
Group
Duke Energy
Colby Bellville
Yes

Duke Energy requests additional information regarding the Footnote 1 exclusion provision. As written, it is unclear as to what exactly is needed to provide demonstration for this provision, as well as the frequency of the demonstration necessary to remain compliant. For example, if an entity performs an analysis to prove that the exclusion was applicable to a specific Automatic Reclosing Relay, would the entity need to run another analysis ever again, or would an analysis only need to be done if there was a change to the Balancing Authority Area's system or the BES? Also, Duke Energy suggests that because Footnote 1 effectively acts as an exclusion, that the SDT consider placing the Footnote in the standard itself.

Yes

Duke Energy requests clarification from the SDT as to whom they envision identifying the newly acquired Automatic Reclosing Components, how they must identify, and what documentation is needed to show correspondence with an entity's maintenance program. Also, Duke Energy suggests that the SDT consider placing the Implementation Plan for Newly Identified Automatic Reclosing Components in the standard itself, and not as its own document.

Group

MRO NERC Standards Review Forum (NSRF)

Russel Mountjoy

No

Please clarify what is meant by "BES elements at substations one bus away from generating plants". How is the one bus criterion applied at a generating station with power transformation and multiple voltages? The use of the words substation and "one bus away" leaves the definition open to interpretation when a plant is connected at one voltage class and there are reclosing relays at another voltage class. The higher or lower voltage class bus could be read as "one bus away" and yet at the same substation. It may be necessary to speak in terms of either substations or electrical busses. It may also be necessary to define how a different voltage class bus should be treated. Could a large power transformer between voltage classes be equivalent to 10 circuit miles of impedance? Was the reclosing only meant to apply at the same voltage class?

No

The implementation plan should be based upon the existing maintenance schedules for the affected BES components.

Individual

Thomas Foltz

American Electric Power

No

Regarding 4.2.6.2 in the Facilities section, the verbiage used suggests that substations that are one bus away, but connected by a transformer instead of a line, would be in scope. This

would seem technically inappropriate, as a transformer would typically have a higher impedance than 10 miles of line and therefore premature reclosing at these substations should not affect generators one bus away in these cases. If such substations were to be included, it would unnecessarily bring into scope many more reclosing relays than intended by FERC Order No. 758. AEP envisions voting affirmative on this proposed standard if our concerns regarding scope are eventually addressed.

No

AEP will reserve its comments on the proposed implementation plan until its concerns on scope are eventually addressed. Due to the current volume of standards development activity, AEP is not able to apply the same level of rigor to this request for comment as we would normally. As a result, the comments provided in this response are those we deemed the most significant, and do not necessary reflect all the issues that AEP may, at some time, choose to address.

Individual

Michelle D'Antuono

Occidental Chemical Corp. (Ingleside Cogeneration LP)

Yes

Ingleside Cogeneration agrees with the distinctions that the project team has made to determine which automatic reclosing components may pose a risk to the BES, and therefore should be subject to PRC-005-3. Clearly those that are incorporated in an SPS have a direct reliability impact. However, it is reasonable to limit applicable to reclosing systems that reside at or near significant generation facilities. We also agree that an exclusion should be allowed wherever the relay owner can demonstrate that the generator protection scheme is configured to withstand a Fault time frame of twice the normal clearing time without severing the Facility from the BES. This is a very conservative risk threshold and properly focuses compliance resources on the most prevalent threats to BES performance. Lastly, the limits of the control circuitry functionality testing are also appropriate. The prior version of PRC-005-3 included testing through the breaker trip coils – which may also inadvertently lock out other ancillary functions. Since the only reliability concern is that the reclosing relay will misoperate in a manner that will result in a premature closing signal, it is appropriate that the functional test required by NERC focuses only on that point.

No

Ingleside Cogeneration believes that the one year time-frame given to incorporate all the components of Automatic Reclosers newly identified as applicable to PRC-005-3 due to a generation change in the BA footprint is insufficient. It is appropriate to require the PSMP to be updated with the new components by that date, but not to conduct the first full set of maintenance activities. Our primary concern is that Ingleside, as a Generator Owner, will not receive timely notification that a substantive change has been made. And although we are willing to reach out to our Balancing Authority on a regular basis – or to establish a notification process – this is not a coordination activity that either of us have historically

pursued. Furthermore, the recloser relays maintenance is handled during planned outages. At the very least, we would need an additional three years to schedule and execute the Table 4 maintenance activities in a quality manner. Since a single miss to PRC-005-3 would result in a big dollar penalty, we believe that there is some reasonable leeway that should be provided. Four years beyond the date of the generation change is not excessive – particularly since the failure of reclosing relays has not been found as the cause of a major BES event, or even a common issue in less extensive failures.

Group

PacifiCorp

Ryan Millard

Yes

Yes

Individual

Nazra Gladu

Manitoba Hydro

No

Although Manitoba Hydro will continue to maintain our “negative” vote for this standard based on concerns from the PRC-005-2 version, we do offer the following comments to the SDT in regards to PRC-005-3: (1) Table 1-4(a), (c), (f) - Manitoba Hydro suggests that the maintenance activity for electrolyte level inspections would be more appropriately specified on intervals of six calendar months, rather than on a four month basis. It is our experience that maximum maintenance intervals of 6 months are adequate at addressing reliability. Requiring four month intervals would be needlessly burdensome to industry without achieving additional reliability benefit. Moreover, the maintenance activities which require inspections to be completed every 18 months will oblige entities to make an additional site visit every second year. In effect, entities are being asked to check equipment (e.g. electrolyte levels) on month 16, return on month 18 to check equipment components such as ohmic values, charge float voltage, etc, and then required to return again on month 20 to check electrolyte levels, which is excessive. Instead, Manitoba Hydro suggests a more manageable maximum maintenance interval of 4 calendar months for these types of maintenance activities (station dc supply voltage, electrolyte level and for unintentional grounds).

No

Although Manitoba Hydro will continue to maintain our “negative” vote for this standard based on concerns from the PRC-005-2 version, we do offer the following clarifying comments to the SDT regarding PRC-005-3: (1) General comment - the words “Automatic Reclosing Components” are both capitalized and de-capitalized throughout the document. For example,

within the definition of a Protection System Maintenance Program (PSMP) the words are de-capitalized, but are then capitalized in PRC-005-3 R3. For consistency, Manitoba Hydro suggests selecting one or the other. (2) Definitions of Terms Used in Standard, PSMP - capitalize the word "component" for consistency with the rest of the standard. (3) Background 4, Retirement of Existing Standards, Implementation Plan for Requirements R1, R2 and R5, Implementation Plan for Requirements R3 and R4, Implementation Plan for Requirements R1, R2 and R5 and Implementation Plan for Requirements R3 and R4 - replace "Board of Trustees" with "Board of Trustees'" for consistency with other standards.

Individual

Travis Metcalfe

Tacoma Power

Yes

Additional Comments- 1. In the definition of a PSMP, captialize 'components'. 2. In the definition of a PSMP (including Supplementary Reference), capitalize 'automatic reclosing'. 3. In the Implementation Plan, change "The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of first calendar quarter..." to "The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter..."

Yes

Individual

Alice Ireland

Xcel Energy

Yes

We are supportive of the changes made. But we do have two additional comments: a. The inclusion of Table 4-2(b) in PRC-005-3 raises the concern of where this testing would have been required in PRC-005-2 and raises uncertainty about the SDT's intentions for the testing requirements for all the various possibilities for actuation of SPS mitigating devices. We were under the impression that row 1 of Table 1-5 in PRC-005-2 required 6 year verification of trip coils or actuators of circuit breakers or other SPS mitigating devices. What if an SPS calls for the closure of a normally open breaker and that close signal is accomplished via some means other than a reclosing relay? Where would the testing of such a breaker closure be required by PRC-005-2 or PRC-005-3? The way PRC-005-3 Table 4-2(b) is phrased it would appear that trip coil operations for circuit breakers in protection systems or SPS's would be required per Table 1-5, row 1 and that close coils that are parts of reclosing schemes are required per tested by Table 4-2(b), row 1, but there does not appear to be testing requirements for any other SPS mitigating devices such turbine runbacks, closure of normally open breakers, disconnect operators, etc. Please clarify testing requirements for SPS mitigating devices outside of breaker trip coils (Table 1-5, row 1) and close coils as utilized in SPS reclosing

schemes (Table 4-2(b)) - e.g. turbine throttle valve runback, LTC blocking or enabling, closure of normally open breakers, MOD operation, etc., etc. This appears to be a reliability gap in both PRC-005-2 and PRC-005-3. b. The applicability of reclosing to the Generator Owner & Transmission Owner is dependent upon the GO & TO knowing the characteristics of the Balancing Authority. GOs & TOs do not have this knowledge. There should be an obligation of the BA to inform (and update as needed) the GO and TO of the gross MW value of the largest unit in the BA footprint (or determine the appropriate entity to update the GO & TO). This could be accomplished by adding BA's as an applicable entity to PRC-005-3 and adding a requirement for this notification of TO's and GO's by the BA to PRC-005-3. Alternatively, the applicable entities for PRC-005-3 could be left as is and the requirement for BA's to notify TO's and GO's could be accomplished by adding a new requirement to a more appropriate standard.

No

The implementation plan for the initial implementation of the program allows for a gradual implementation of requirements R3 and R4 for reclosing relay maintenance activities for those relays determined to be in scope such that 30% must be compliant within 36 months of regulatory approval, 60% compliant within 60 months of regulatory approval, and 100% compliant within 84 months of regulatory approval. The additional implementation plan requires 100% compliance within the next following calendar year even in those circumstances where the retirement of the largest unit in the balancing authority would result in an entirely different set of reclosing relays to be in scope. For consistency, it would be far more reasonable for the additional implementation plan to be aligned with the requirements of the original implementation plan for R3 and R4. Specifically, entities should be compliant with R1, R2, and R5 for the newly in scope schemes at the start of the first calendar quarter 12 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area. For requirements R3 and R4, entities shall be 30% compliant within 36 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area, 60% compliant within 60 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area and 100% compliant within 84 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area.

Individual

Daniel Duff

Liberty Electric Power

No

4.2.6.1 uses the phrase "greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area" as one determinant for inclusion of relays into the standard. However, generators do not have a wide area view of the system, and cannot

determine the gross capacity of the largest BES generating unit. Does this value include all generation which could trip simultaneously at a single generating location? All generation which is connected through a single step-up transformer? Further, changes outside of the control of a generator could move relays in or out of the program. If retirement of an asset lowers the gross capacity value of the largest BES generating unit, would relays immediately be pulled into the program? Finally, there is no requirement for the BA to provide the gross capacity value to generation owners. The BA should be added to the list of covered entities, with a requirement to provide to all entities in their balancing area notice of the gross capacity of the largest generating unit once per calendar year, and within 30 days of a change in this value. Another section should be added to the standard to list the implementation requirements for existing assets when a covered relay enters the program.

No

The program as written requires 30% compliance at 60 months. This implies two instances of 12-year maintenance have to occur in 5 years, or 19 years earlier than should be required. The plan should be changed to all relays must have the first maintenance completed by 144 months from the effective date of the standard.

Individual

David Jendras

Ameren

Agree

We agree with the SERC Protection & Control Subcommittee (PCS) comments and include them by reference.

Individual

Bill Fowler

City of Tallahassee

Yes

Yes

Individual

Michael Falvo

Independent Electricity System Operator

No

The IESO believes that the analysis required by the Footnote 1 is out of the scope of PRC-005-3, which is to document programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the BES so that they are kept in working order. In addition, the analysis required by the Footnote 1 is vague and difficult to assess compliance. In the IESO's view, contingencies and related tests performed in transient simulations should be defined in

the planning standards (eg. the TPL standards), instead of PRC-005-3 which is drafted for maintenance purposes. We suggest removing the Footnote 1 from the draft standard, or in case it is retained it should be revised to address the aforementioned concerns.

No

We appreciate the SDT's effort to insert appropriate wording to remove a potential conflict with Ontario regulatory practice with respect to the effective date of the standard. However, there are still a couple of places where this insertion is missing. Please insert: ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." prior to the wording ",or in those jurisdiction...." in Section 4 on P.2 and in the first paragraph under the Retirement of Existing Standards" on P.3.

Individual

Gerald Farringer

Consumers Energy

No

Consumer's Energy Ballot member is voting NEGATIVE on Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) PRC-005-3 since the standard does not address how each entity is expected to obtain the required information "the gross capacity of the largest BES generating unit with the Balancing Authority Area" (in section 4.2.6.1) and know when it changes.

No

Consumer's Energy Ballot member is voting NEGATIVE on Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) PRC-005-3 since the standard does not address how each entity is expected to obtain the required information "the gross capacity of the largest BES generating unit with the Balancing Authority Area" (in section 4.2.6.1) and know when it changes.

Individual

Anthony Jablonski

ReliabilityFirst

Yes

ReliabilityFirst votes in the affirmative because the modifications to this standard further establishes minimum maintenance activities for Automatic Reclosing Component Types and the maximum allowable maintenance intervals. ReliabilityFirst offers the following comments for consideration: 1. Table 4-2(a) and 4-2(b) - ReliabilityFirst seeks the technical justification for the maximum maintenance interval of 12 years for unmonitored control circuitry associated with Automatic Reclosing. 2. Applicability section 4.2.6.1 - ReliabilityFirst recommends adding the term "nameplate rating" to clarify which generating plants are required have Automatic Reclosing applied. Without this clarifier included, the term "total installed gross generating plant capacity" is subject to interpretation. For example, a plant

may have multiple different values for its gross generating plant capacity but a plant will always have one static nameplate rating. The term “nameplate rating” is also consistent with the new NERC BES definition language.

Individual

Tracy Goble

Consumers Energy Co.

Consumers Energy Co.

No

Consumer’s Energy Ballot member is voting NEGATIVE on Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) PRC-005-3 since the standard does not address how each entity is expected to obtain the required information “the gross capacity of the largest BES generating unit with the Balancing Authority Area” (in section 4.2.6.1) and know when it changes.

Group

Pepco Holdings Inc & Affiliates

David Thorne

No

1) In section 4.2.6.1 the term “gross generating plant capacity” is used. We assume this refers to nameplate MVA ratings. To avoid confusion as to what unit of capacity (MVA or MW) is to be used to evaluate these criteria we suggest the phrase be clarified as “gross generating plant capacity (in MVA)”. 2) NERC’s System Analysis and Modeling Subcommittee (SAMS) recommended limiting the applicability of automatic reclosing within this standard to only those installations that would impact the reliability of the BES. Section 4.2.6.1 uses criteria based on the “gross generating plant capacity”. Neither the PRC-005-3 standard itself, nor the Supplementary Reference document explains how to calculate this gross capacity number. Consider a generating plant that has a total of 600 MVA of installed capacity connected to a 230kV bus. There are also units within the same “power plant” with 200 MVA of capacity connected to a 69kV bus. The 230kV and 69kV busses are interconnected by an autotransformer. The “gross generating plant capacity” is 800 MVA, however 200 MVA of this is connected below 100kV and is not considered BES generation. If it is not considered BES generation, then it should be excluded from the calculation of gross plant capacity in Section 4.2.6.1, as the loss of this generation would not directly affect the reliability of the BES. 3) In some switchyard arrangements generating units within the same power plant are connected to separate switchyard busses that are not connected together. This may be done for reliability reasons and to control fault current levels. In these situations, the calculation of gross plant capacity in Section 4.2.6.1 should be based only on the amount of generation directly connected to the individual bus, and not the total amount in the plant. 4) The NERC SAMS review concluded that automatic reclosing mal-performance affects BES reliability

when “inadvertent reclosing near a generating station subjects the generation station to severe fault stresses”. The concern appears to be potential shaft torque damage, or instability, of rotating machines to automatic reclosing mal-performance. That being the case, generation sources that are not subject to severe fault stresses, such as inverter based generation, or static reactive sources (SVC’s, capacitor banks, etc.) should not be included in the calculation of gross plant capacity. However, since synchronous condensers are subject to the same fault stresses as synchronous generators they should probably be included in the gross plant generation calculation, providing they are interconnected at 100kV, or above. 5) To adequately address the concerns raised in the above sets of comments we suggest Section 4.2.6.1 be re-worded as follows to provide clarity and eliminate confusion on how to evaluate this plant capacity calculation: “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 (in MVA) connected to that bus is greater than the gross capacity (in MVA) of the largest BES generating unit within the Balancing Authority Area.” In addition, a qualifying footnote defining “gross generating plant capacity” needs to be added as follows: “For application of 4.2.6.1 gross generating plant capacity is defined as the sum total of the nameplate ratings, expressed in MVA, of all BES rotating machine generating units (including synchronous condensers) that are connected to a common BES switchyard bus.” Also, specific examples showing how to calculate “gross generating capacity” should be included in the Supplemental Reference document in order to illustrate and clarify the issues described in the above comments. How will the applicable functional entities be aware of the largest (or change in the largest) BES generating unit within the BA area?

No

In order to verify the reclosing scheme performance on any newly identified busses, resulting from generation capacity increases, it may require scheduling sequential line outages on all BES lines emanating from the bus in order to test breaker auto-reclosing operations. Also, based on system operating conditions, these individual line outages may require coordination with certain generation outages. As such, due to the outage coordination necessary to perform this testing, it may not be possible to complete all testing and maintenance activities on these newly identified facilities by the end of the following calendar year. For this reason, we would suggest the following language (similar to that used in the first bullet of R3/R4 Section 5 of the April 2013 draft of the PRC-005-3 Implementation Plan) be used for the implementation plan for these newly identified Automatic Reclosing Components: “The responsible entities must complete the maintenance activities, described in Table 4, for any newly identified Automatic Reclosing Components, resulting from the addition, or retirement, of generating units; or increases of gross generation capacity of individual generating units or plants within the Balancing Authority area, by the first day of the first calendar quarter thirty-six (36) months following implementation of the capacity change, which resulted in the identification of these new Automatic Reclosing Components (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage

Individual

John Seelke
Public Service Enterprise Group
No
Automatic reclosing systems, except for those which are an integral part of an SPS, are not part of Protection Systems that are designed and installed to detect and protect the BES from damage from faults and to keep blackouts localized, i.e., prevent cascades. Autoreclosing relays and systems are installed simply to automate an action by a system operator to close a breaker which automatically tripped, and with one specific possible exception, contribute very little to BES reliability. Besides the SPS, the one possible exception may be in those areas where by virtue of the transmission system configuration rapid reclosing of a tripped breaker is needed to minimize stability issues. PSEG agrees that reclosing relays may be significant to that specific circumstance, i.e., where rapid action is needed to avoid system instability. To identify those specific locations and circumstances and limit the inclusion of such relays to those where it is necessary, PSEG suggests that the drafting team incorporate language similar to that in the Transmission Relay Loadability Standard PRC-023-2 R6 which could be modified for PRC-005-3 to read as follows: "Each Planning Coordinator shall conduct an annual assessment to determine the specific locations/circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers with automatic reclosing relays must comply with the maintenance and testing requirements for such relays under this standard." The Planning Coordinator has the expertise and skills to make this determination; many if not most BES asset owners do not. Power systems are designed to deal with permanent faults, not temporary faults. The extra cost of inclusion of many automatic reclosing relays in the maintenance and testing program would yield little or no benefit to reliability of the BES. Only those defined as essential by the Planning Coordinator should be included in this Standard.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
The selection criteria proposed to identify the reclosing relays that affect the reliability of the Bulk Electric System remains unclear. Please clarify what is meant by "BES elements at substations one bus away from generating plants". How is the one bus criterion applied at a generating station with power transformation and multiple voltages?
No
The implementation plan should be based upon the existing maintenance schedules for the affected BES components.
Individual
Kayleigh Wilkerson

Lincoln Electric System
Agree
MRO NERC Standards Review Forum (NSRF)
Individual
Jonathan Meyer
Idaho Power Company
Yes
No
The change in generation could bring in significant numbers of additional units to be added to the testing and maintenance procedures. We would prefer a percentage based approach similar to the implementation plan for the other table items in PRC-005-2.
Group
Dominion
Louis Slade
No
The SDT did not address concerns relative to how an entity could determine the gross capacity of the largest BES generating unit within the Balancing Authority Area. Dominion suggests the SDT include a requirement that the BA post or make such information available to all entities in its area. The SDT did not address concerns that only planning entities are typically afforded access to the models or information, or have the technical skills necessary to be able to make the determination necessary to allow the exclusion included in footnote 1.
No
Given that most of the Maximum Maintenance Intervals appear to be in the 4-6 year range, we believe that implementation for newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area should be extended to allow up to 36 months from BA notification of such change
Individual
Scott Langston
City of Tallahassee
Yes
Yes
Group
SERC Protection and Controls Subcommittee

David Greene
Yes
1) Please provide FAQ examples to clarify the meaning of ‘total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit’. Our take is the gross MVA for FAC-008 would be appropriate. But there are several MOD standards, including some pending FERC approval, that will prove MW and MVAR ‘capability’ not ‘capacity’. 2) We request that the SDT modify the FAQ 2.4.1 to include “typically IEEE Device No. 79” in referring to the Automatic Reclosing relay because this helps clarify the scope. Begin the answer with “Yes. Automatic Reclosing includes reclosing relays (typically IEEE Device No. 79) and the associated dc control circuitry.”
No
1) We prefer that maintenance for newly identified Automatic Reclosing Components be completed within 3 calendar years. This is more consistent with the phased in approach that applies to the overall implementation. 2) We prefer a single document with the implementation plan; please combine the 2 documents. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Group
North American Generator Forum Standards Review Team
Patrick Brown
No
This standard presents compliance documentation uncertainties for applicable reclosing relays defined in Applicability Section 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”. This standard now assumes that GO/TOs are going to coordinate and document that they have contacted the BA to determine the largest unit in the area and then determine if the reclosing relays are/are not applicable but does not mention it in the measures. How much coordination and documentation is required by a GO and its associated SWYDs TO to prove that the generation facility does or does not exceed the largest BES unit? Does this become part of a PRC-001 requirement to coordinate protection systems?
No
1. Regarding the implementation plan for this project, the SRT is concerned with the following: “For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4: The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3.” This would require two cycles of 12-

year maintenance in five years for 30% of your affected equipment. We recommend that the implementation plan be changed to require that 100% of the affected relays have one maintenance performed by 144 months from the implementation date of the standard. 2. The implementation plan states: "For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3." However, If there is no specific 'bookend' required, and the cycle is truly a 12-year cycle, no evidence of testing or maintenance should be required prior to 144 months from the enforcement date of the standard; but the proposed implementation plan requires the work at 36 months, 60 months, and 84 months, which is obviously short of a 12-year cycle. A Compliance Enforcement Authority could apply this in the following manner: Entity Y has four reclosing relays, all tested and installed on August 1, 2004. The new PRC-005 Standard becomes effective on July 1, 2014. On August 2, 2014 entity Y could be found in violation if one of the four relays has not gone through the new 12-year required cycle. If the language was changed to 100% compliance by 144 months, with all the earlier steps eliminated, it would work. Specific language needs to be in place noting that no evidence shall be required for any testing prior to the enforcement date, and the 12-year clock starts on that day. The following change would need to be made also: "For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until 288 months following the enforcement date of PRC-005-3."

Individual

Louis C. Guidry

Cleco

No

We do not believe reclosing relays are protective devices and therefore are not subject to this level of oversight. Second, the strongest justification was that if the relay failed to operate correctly and reclosed instantaneously, the generator would be subject to additional fault duty. We have not seen such a failure and do not see the justification for including reclosing relays or restoration devices in a Protection System Maintenance & Testing Standard. Major storm events near the station or breakers failing to latch are far more likely to cause sequential faults.

No

We do not believe reclosing relays are protective devices and therefore are not subject to this level of oversight. Second, the strongest justification was that if the relay failed to operate correctly and reclosed instantaneously, the generator would be subject to additional fault duty. We have not seen such a failure and do not see the justification for including reclosing relays or restoration devices in a Protection System Maintenance & Testing Standard. Major storm events near the station or breakers failing to latch are far more likely to cause sequential faults.

Group
Oklahoma Gas & Electric
Terri Pyle
No
<p>In the draft Standard and the Supplementary Reference, a lot of detail was deleted from the definition of Automatic Reclosing. The revised definition no longer includes the phrase "but excluding breaker internal controls such as anti-pump and various interlock circuits." Does this imply that those components are now included in the definition of Automatic Reclosing? In reference to these components, the Supplementary Reference document (in section 15.8.1) states that, "These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4." The Standard needs to be explicit on what is and is not required to be tested as part of an entities PRC-005 maintenance and testing program rather than leaving it open to interpretation. In 4.2.6.1 of the Applicability section of the draft Standard, reference is made to the total installed gross generating capacity of a generating plant which is then compared to the gross generating capacity of the largest BES unit in the Balancing Authority Area. It would be helpful if the SDT provided some examples (including some that references how to address combined cycle units/plants) in the Supplementary Reference document to help entities understand and properly apply Section 4.2.6.1 of the Standard.</p>
Yes
Group
PPL NERC Registered Affiliates
Brent Ingebrigtsen
No
<p>1) There are currently two NERC approved projects filed at FERC (PRC-005-1.1b and PRC-005-2). NERC should consider waiting to proceed with this project until the current projects are ruled on and FERC provides further direction. 2) For 4.2.6, for reclosing capability, it is unclear what functionality is to be tested. Please define. 3) For PRC-005-3 section 4.2.6.2, please provide the technical basis for this application of the Standard. Specifically, this application states for Automatic Reclosing: "Applied on 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." Please provide the technical basis/reasoning for the 10-mile criteria. At a recent North American Transmission Forum Workshop on Protection System Maintenance Program it was implied that the 10 mile rule is for cases where a generator has a short connection to another company's substation. Please clarify if this is the case. 4) For PRC-005-3 section R1, consider adding the following language that is used for PRC-005-1.1b "each Generator Owner that owns a generation or generator interconnection</p>

Facility Protection System...” This is NERC-approved language that has been through the standards development process and has technical justification through Project 2010-07. 5) Please provide the technical basis for R1.1 which requires battery testing for DC Supply Component Type Protection Systems to be time based. 6) Table 1-2 of PRC-005-3 requires functional testing of non-monitored communication systems on a 4 month cycle. Please specify NERC’s criteria for the functional testing (what attributes to be tested). Additionally, specifically define monitoring criteria and data intervals for continuous monitoring of communications systems (to see if check back (fail/no fail) monitoring is adequate). 7) This standard presents compliance documentation uncertainties for applicable reclosing relays defined in Applicability Section 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”. This standard now assumes that GO/TOs are going to coordinate and document that they have contacted the BA to determine the largest unit in the area and then determine if the reclosing relays are/are not applicable but does not mention it in the measures. How much coordination and documentation is required by a GO and its associated switchyards. Does the TO need to prove that the generation facility does or does not exceed the largest BES unit? Does this become part of a PRC-001 requirement to coordinate protection systems?

No

1. Regarding the implementation plan for this project, the PPL NERC Registered Affiliates are concerned with the following: “For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4: The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3.” This would require two cycles of 12-year maintenance in five years for 30% of your affected equipment. We recommend that the implementation plan be changed to require that 100% of the affected relays have one maintenance performed by 144 months from the implementation date of the standard. 2. The implementation plan states: “For activities being added to an entity’s program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.” However, If there is no specific ‘bookend’ required, and the cycle is truly a 12-year cycle, no evidence of testing or maintenance could be required prior to 144 months from the enforcement date of the standard; but the proposed implementation plan requires the work at 36 months, 60 months, and 84 months, which is short of a 12-year cycle.

Group

Southern Company

Wayne Johnson

No

1) We believe that there should be a Requirement for the BA to initially inform the TOs and GOs in their area which units are in scope. Minimally, there must be a requirement that the

BA identify the 'largest BES generating unit' and inform all the TOs and GOs in their area. 2)Secondly, related to 1) above, there must be a requirement that the BA inform all the TOs and GOs in their area when a change occurs related to the 'largest BES generating unit'.
No
Southern Company believes that the two implementation plans associated with the Standard are in conflict. It can be interpreted that all automatic reclosing components will be 'newly identified'. As such they would be required to be completed by the end of the following calendar year. We believe that the intent was to have the initial applicable Automatic Reclosing Components to have the same phased in completion dates that were brought forward from PRC-005-2. If that was the intent, a potential conflict exists since after the initial phased in schedule up to 12 yrs is set, a change in the unit applicability could occur one year later which could in the case of 'largest unit' retirement bring many more locations into scope all of which would be newly identified and be subject to the one calendar year requirement. Bottom Line is that the Implementation plan needs to be revisited. Related to the comment to #2 above, we do not specifically see a timeline identified to include the following: 1) Identification to identify the units and components covered. 2) Identification of the components that may be excluded per the Note. 3) Modification to the PSMP 4) Actual Implementation If the intent is for all this to be covered in R1 and R2, we question this for the following reasons: • Is this enough time for the initial steps noted above, and • This result in multiple dates for compliance with R1 and R2
Individual
Brett Holland
Kansas City Power & Light
Agree
SPP - Robert Rhodes
Group
Hydro One Networks Inc.
Sasa Maljukan
Agree
IESO and NPCC RSC
Individual
Brian Evans-Mongeon
Utility Services
Agree
NPCC Reliability Standards Committee
Group
ACES Standards Collaborators
Jason Marshall

No

(1) We find that the changes are non-substantive and do not present a problem. However, we continue to be concerned about modifying this standard when there is another version pending before the Commission. We believe it will only cause confusion. Given that this standard is historically one of the top ten most violated standards and the most violated non-CIP standard, industry does not need to be burdened with further confusion that will only cause additional violations. One example of the confusion is the implementation plan of the proposed draft. If the PRC-005-2 standard was already enforceable, the implementation plan could focus only on auto-reclosing which would avoid the confusion. (2) Because there were no general feedback questions asked and there is no other appropriate question to place our other concerns with the proposed standard, we are inserting them here. (3) The implementation plan creates confusion with dual conflicting parallel dates. The confusion is understood by comparing PRC-005-2 implementation plan to the PRC-005-3 implementation plan. For example, the implementation plan for PRC-005-2 requires the responsible entity to be at least 30 percent compliant on the first day of the first calendar quarter 24 months following applicable regulatory approval for maintenance activities with a three year interval. The PRC-005-3 implementation plan is identical. Thus, if FERC approves PRC-005-2 such that it has an effective date of June 1, 2014, the responsible entity will have to be 30 percent compliant with R3 and R4 for equipment with three-year interval maintenance cycles by July 1, 2016. If FERC then approves PRC-005-3 such it has an enforceable date of September 1, 2015, the responsible entity will have to be 30 percent compliant with R3 and R4 for equipment with a three-year interval maintenance cycles by October 1, 2017. Thus, there will be two different conflicting dates for the 30 percent compliance level. Which applies? If the second applies, this is like resetting the compliance date. Furthermore, there is unnecessary confusion with the 30 percent compliant metric, as this could change from the two different implementation plans if additional equipment is installed during the implementation plan. There are too many compliance risks of having implementation plans overlapping or coming into effect in a short amount of time. This proposal mirrors the issues of the implementation plans with CIP version 4 and CIP version 5. FERC granted an extension in order to allow responsible entities to more efficiently utilize resources to transition to the next version. We, as an industry, should learn from this experience and not rush to the next version of the standard prematurely. (4) We disagree with the statement (second paragraph first sentence and first bullet) in the general considerations section of the implementation plan that states the responsible entities must be prepared to identify Automatic Reclosing components during the transition from version 2 to version 3. While we agree that this ultimately will be necessary at some point in the transition to prepare for the compliance date, we are concerned that an auditor could interpret this implementation plan as requiring the responsible entity to develop an inventory of Automatic Reclosing components prior to the effective compliance date. A standard cannot retroactively require actions to be completed prior to its effective date. This identification of Automatic Reclosing components presents serious compliance issues and we recommend striking it in its entirety. (5) We disagree with the statement (second paragraph first sentence and second bullet) in the general considerations section of the implementation plan that states the responsible entities must

be prepared to identify “whether each component has last been maintained according to PRC-005-2 (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof”. We do not have an issue if this statement applies only to the Protection System components because they have been under these standards for some time. However, this statement could be viewed as applying to Automatic Reclosing components and it should not because they have never been subject to any standard. While most responsible entities will have maintained their Automatic Reclosing components, they simply were not required to maintain them and, thus, the documentation may not be sufficient to demonstrate prior maintenance activities. Maintenance activities for Automatic Reclosing components are not required until PRC-005-3 is enforceable. (6) We do not understand why PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 will not be retired for 156 months or 13 years. That is quite a long time for these standards to be effective in parallel. This poses a potential for double jeopardy and we recommend retiring these standards at the same time the new standard becomes enforceable. (7) We find the language in section 3 of the implementation plan for R3 and R4 confusing. That section proposes to require the responsible entity to comply with R3 and R4 for 30 percent of the Protection System components that are subject to three-year maintenance intervals. However, this language “or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage” is added as a caveat. We are unsure how to interpret it. Does this mean that if a generator has three-year maintenance interval that 30 percent of its Protection System components must meet compliance at the conclusion of the first succeeding maintenance outage or it is an exception and all of its Protection System components must meet R3 and R4 compliance obligations by the same date? (8) Section 4.2.6.1 of the applicability section of the standard is inconsistent with the proposed definition of the Bulk Electric System (BES) and may be inconsistent with existing definitions that vary by region. Since Inclusion I2 includes the generator and generator step up (GSU) transformer as part of the BES, what exactly would constitute the BES bus? The low side bus of the GSU transformer, the high side bus or some other location? All of these are part of the BES. This section needs further clarification. (9) Section 4.2.6.2 of the applicability section of the standard needs further refinement. What would constitute one bus away from the generating plant? What constitutes the plant? The electrical machine, turbine, GSU, and switchyard? What if there is more than one switchyard? What if the switchyard is not on the immediate property but short distance away? Some additional refinement would help to answer these questions. We suggest utilizing the GSU as demarcation point to help clarify. (10) The evidence retention section needs to clarify that the responsible entity is not required to keep “documentation of the two most recent performances of each distinct maintenance activity “during the initial implementation of the standard for Automatic Reclosing components. This clarification will help avoid the problems that occurred with PRC-005-1 when auditors requested evidence from before the effective date of the requirements. The bottom line is that a standard cannot be retroactive and cannot compel evidence from before the effective date. This needs to be clear. (11) The evidence retention period is excessively long, is inconsistent with the Reliability Assurance Initiative (RAI), and is inconsistent with the Rules of Procedure. Since some Automatic Reclosing component maintenance intervals are 12

years, retaining the two most recent performances of each maintenance activity could result in evidence retention periods of almost 36 years. Entire careers will be worked before this evidence can be destroyed. Given the length of time, it is highly likely that responsible entities will lose some of the documentation which will result in paper violations that do nothing to support reliability. This is contrary to the RAI which is trying move to a forward looking compliance model that provides reasonable assurance of compliance. Furthermore, the evidence retention period is longer than the six year audit cycle for TOs, GOs, and DPs which is inconsistent with section 3.1.4.2 of Appendix C - Compliance Monitoring and Enforcement Program of the NERC Rules of Procedures. This section is very clear that the evidence retention cannot exceed a period prior to the last audit. (12) We suggest that Table 4-2(a) should be clarified that it only applies to those Automatic Reclosing components that are at large generator plants or close to large generator plants per applicability section 4.2.6.1 and 4.2.6.2 respectively. Otherwise, there may be confusion when compliance and enforcement personnel look at the table. They may view that it will apply to all Automatic Reclosing components that are not an integral part of a Special Protection System (SPS) including those are not close to large generators.

No

(1) We agree with the need for the additional implementation plan but find it confusing. First, we think that the compliance date should be identified as some interval after the commercial in-service date of the change in generation or the official retirement date. Otherwise, there could be confusion in which year the newly applicable Automatic Reclosing components must be compliant. Consider a new unit begins testing on December 1, 2013 and goes commercial January 31, 2014. One could interpret the language in the implementation plan to require the maintenance activities to be completed by December 31, 2014 or December 31, 2015. (2) To avoid the confusion that occurred with PRC-005-1, the implementation plan should state very clearly that the initial maintenance activities must be performed by the compliance date and that no evidence of prior maintenance activities is required. In essence, the compliance date established in this implementation plan due to changes in generation and the overall implementation plan should be very clear that the compliance date established in these plans is the start of the initial interval. To allow the interval to start before the compliance date would be equivalent to making the standard retroactive.

Group

SPP Standards Review Group

Robert Rhodes

No

In the definition of Automatic Reclosing a goodly amount of detail has been deleted from the definition. Does the excluded portion of the definition, specifically breaker internal controls such as anti-pump and various interlock circuits still fall under the standard? The reference document implies that they do, but the revised wording is not clear to us. In 4.2.6.1 reference is made to the total installed gross generating capacity of a generating plant which is then compared to the gross generating capacity of the largest BES unit in the Balancing Authority

Area. Shouldn't the reference to the largest unit also state the installed gross capacity of the unit to prevent any confusion? Also, in selecting to use gross generation numbers, we wonder if consideration was given to generation values used in other standards such as BAL-002 and BAL-003 which tend to lean toward net generation values rather than gross. In the Supplementary Reference we suggest replacing the term 'supervisor' on Page 92 in Section 15.8.1 FAQ in the 7th line of the 1st paragraph in the response to the 2nd question with 'supervision'. The sentence would then read '...applicability of associated supervision/conditional logic and the...'

Yes

Individual

Texas Reliability Entity, Inc.

Texas Reliability Entity, Inc.

No

We feel that the proposed maintenance activities in tables 4-1 and 4-2 do not necessarily address all of the typical failure modes of reclosing relays and control circuitry associated with them and offer the following comments: 1) Definition of Automatic Reclosing: Is it the SDT's intention that "Control circuitry associated with the reclosing relay" includes a separate sync check relay that may be used in the reclosing scheme? The definition is not clear and the SDT may want to clarify. 2) Table 1-3: The SDT may want to consider adding an activity to verify voltage signals are provided for reclosing relay sync check functions. 3) Table 4-2(a) and 4-2(b): The SDT may want to consider including activities to verify that auxiliary relays in the reclosing scheme (i.e. bus differential or breaker failure lockout relays) properly inhibit reclosing. The SDT may also want to consider including activities to verify sync check functions depending on the system design (i.e. hot bus-hot line, hot bus-dead line, etc.). These two activities are necessary to verify that the reclosing scheme will not issue a reclose signal when it is not desired. 4) Table 4-2(b): Suggest rewording the 2nd block to say "Verify all paths of the control circuits ***including all auxiliary relays*** associated with Automatic Reclosing..."

Yes

Individual

Bradley Collard

Oncor Electric Delivery Company LLC

Yes

Yes

Individual

Ryan Walter
Tri-State Generation and Transmission Association, Inc.
No
<p>Tri-State Generation and Transmission Association, Inc. finds that Table 4-1 is too inclusive and should include a restriction for only automatic reclose relays/functions that are required for system stability, with a list of which those should be as per SAMS, such as SPS and near generation. Table 4-1, as written, captures more equipment than is necessary, creating an undue administrative burden with little, to no, benefit to the reliability of the BES. Adding a compliance liability for reclosing relays that do not impact system stability could lead to industry removing many of the reclosing relays used for expeditious restoration. This does not improve system reliability. Also, since the majority of reclosing functions utilizing microprocessor relays reside within the microprocessor protective relay, the documentation for this testing will be included within documentation already required and provided under Table 1-1. To provide a separate list and documentation for all BES microprocessor reclosing functions will create an undue administrative burden on industry with little to no value to the BES. Further, we recommend the applicability of reclosers is changed to “reclosers identified by the entity’s selection criteria to be critical to the operation of the BES per its Maintenance and Testing Program” to better align with FERC order 758 where FERC recommends “selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System”. Tri-State suggests that Table 4-2(a), Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS, be removed in its entirety or a maintenance activity specific to the circuitry be defined. The maintenance activity required in Table 4-2(a) is not a maintenance activity that verifies the control CIRCUITRY. A close “command” is external to the hardware circuitry. Whether or not that command occurs, does not confirm the functionality of the close circuitry hardware. The timing test for a reclosing function is also usually included within the testing of the protective relay, which is part of Table 1-1 and Table 4-1, making this table slightly redundant to what already exists. A definition of “premature”, giving specific tolerances, will also be required, if kept within the text, to understand at what point a test would fail or a result would be viewed as “non-compliant”. Any test for a microprocessor instantaneous reclose would fail this requirement, as the close command is already present at the beginning of the sequence, hence being “premature”. A PASS test result showing the reclose command was initiated within the tolerance of the relay but prior to the setting could be viewed as “premature” and be interpreted as “non-compliant”. A FAIL test result showing the relay closed well out of the manufacturer tolerance but after the setting would be viewed as “compliant”. If the text and Table remain, the statement: “Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry” should be changed to, “Verify that the close circuitry operates per engineering settings, and not sooner than (tolerance) of the setting.”</p>
No
"Prior to the end of the following calendar year" is a very ambiguous implementation plan and could require entities to be compliant anywhere between 12 and 24 months. TSGT

recommends that the implementation period state 18 months from the first day of the quarter following component identification.
Group
Colorado Springs Utilities
Kaleb Brimhall
No
1.Concerning facilities, would a reliability based method of determining covered facilities more likely better serve the reliability of the BES versus the generation based cap method under 4.2.6? 2.With no standard requiring re-closing relaying be in place, there will be a tendency to disable all re-closing relays to avoid facilities coming under this standard.
Abstained from commenting on this question.
Individual
Michael P. Moltane
ITC
No
4.2.6 references a footnote 1 that is an exclusion. How can an exclusion be put into a footnote? It should be up in the standard, not in a footnote. Regarding 4.2.6.1 for generating plant substations that have generator outputs at separate kV levels where the switchyards are not normally tied together are they treated as separate generating plants? Same question for locations that have generator outputs where the switchyards are not directly tied together. For a location that has a couple Balancing Authority Areas over it is the largest BES generating unit determined by the largest Balancing Authority Area?
Yes
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC PCS
Group
Western Area Power Administration
Lloyd A. Linke
No
Further clarification and definition is required regarding the application of the standard to "premature" closing. Specifically, what is the definition of "premature" and why does the standard not refer to inadvertent or incorrect auto reclosing. Facilities Section 4.2.6.2 applies

to 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. This Section should be clarified and should not include BES elements at those substations connected at a different voltage than the incoming generation circuit. The impedance of any transformation should represent sufficient isolation. It should be clarified that dc control circuitry and power circuit breaker close coils are only included with automatic reclosing that is an integral part of a SPS.

Yes

Consideration of Comments

Project 2007-17.2 Protection System Maintenance and Testing – Phase 2 (Reclosing Relays) PRC-005-3

The Project 2007-17.2 drafting team thanks all commenters who submitted comments on draft 2 of PRC-005-3 standard for Protection System Maintenance and Testing (Reclosing Relays). The standard was posted for a 45-day formal comment period from July 10, 2013 through August 23, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 41 responses, including comments from approximately 149 different people from approximately 85 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's [project page](#).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.¹

Summary Consideration of all Comments Received:

PRC-005-3

There were no changes made to the standard.

Implementation Plan:

In response to comments, the drafting team incorporated the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area” into the full Implementation Plan to consolidate the implementation documents.

Numerous commenters disagreed with the implementation period specified in the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area” stating that it was too short to accommodate the potential number of newly identified Automatic Reclosing Components that could become applicable nor did it provide enough time for potential outage coordination(s) necessary to perform the required maintenance. Upon reconsideration, the drafting team agreed that the proposed implementation schedule for newly

¹ The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

identified Automatic Reclosing Components was inappropriate and could potentially jeopardize reliability by forcing entities to take unscheduled outages to become compliant. The drafting team deemed three years to be sufficient to avoid the reliability concerns and permit entities to implement maintenance in a manner that would be sustainable in the long-term.

In response to a comment, the drafting team inserted the jurisdictional pro-forma language where it had been inadvertently left out of the Implementation Plan. Additionally, NERC will file the errata change with the applicable regulatory authorities as necessary for the PRC-005-2 Implementation Plan.

To avoid confusion, the drafting team modified paragraph 4 of the Background section to remove the references to the implementation timing. The timing is already comprehensively addressed in the implementation plan for each requirement.

Supplementary Reference and FAQ Document:

Additional content was provided to improve the reference document.

Unresolved Minority Views:

- A few commenters objected to the development of PRC-005-3 prior to regulatory approval of PRC-005-2. The drafting team advised that they are acting in accordance with the schedule NERC provided to FERC which outlines the timeframes in which NERC will respond to the directives of FERC Order 758 through the standards drafting process. Specifically regarding reclose relays (Footnote 37), FERC directed NERC to: “By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.”
- Several commenters requested an additional requirement be included in PRC-005-3 mandating that Balancing Authorities provide Transmission Owners, Generator Owners, and Distribution Providers the information identifying the current largest single generating unit in the Balancing Authority Area (described in Applicability 4.2.6), and notify those entities (within a specified time) when this information changes. The SAR for this project does not permit the addition of functional entities to the Applicability section of this standard; therefore, the drafting team is unable to make the requested change. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised.

Index to Questions, Comments, and Responses

- 1. In response to comments, the drafting team revised the previously-posted draft of PRC-005-3 and the Supplementary Reference and FAQ document. Do you agree with these changes? If not, please provide specific suggestions for improvement. 12
- 2. In response to comments, the drafting team developed an “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area” Do you agree with this additional Implementation Plan? If not, please provide specific suggestions for improvement. 42

The Industry Segments are:

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment											
				1	2	3	4	5	6	7	8	9	10		
1.	Group	Guy Zito	Northeast Power Coordinating Council												X
Additional Member		Additional Organization		Region	Segment Selection										
1.	Alan Adamson	New York State Reliability Council, LLC		NPCC	10										
2.	Greg Campoli	New York Independent System Operator		NPCC	2										
3.	Sylvain Clermont	Hydro-Quebec TransEnergie		NPCC	1										
4.	Chris de Graffenried	Consolidated Edison Co, of New York, Inc.		NPCC	1										
5.	Gerry Dunbar	Northeast Power Coordinating Council		NPCC	10										
6.	Mark Kenny	Northeast Utilities		NPCC	1										
7.	Kathleen Goodman	ISO - New England		NPCC	2										
8.	Michael Jones	National Grid		NPCC	1										
9.	David Kiguel	Hydro One Networks Inc.		NPCC	1										
10.	Christina Koncz	PSEG Power LLC		NPCC	5										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment												
			1	2	3	4	5	6	7	8	9	10			
11. Helen Lainis	Independent Electricity System Operator	NPCC	2												
12. Michael Lombardi	Northeast Power Coordinating Council	NPCC	10												
13. Randy MacDonald	New Brunswick Power Transmission	NPCC	9												
14. Bruce Metruck	New York Power Authority	NPCC	6												
15. Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5												
16. Lee Pedowicz	Northeast Power Coordinating 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. Brian Robinson	Utility Services	NPCC	8												
21. Brian Shanahan	National Grid	NPCC	1												
22. Wayne Sipperly	New York Power Authority	NPCC	5												
23. Donald Weaver	New Brunswick System Operator	NPCC	2												
24. Ben Wu	Orange and Rockland Utilities	NPCC	1												
25. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3												
2.	Group	Colby Bellville	Duke Energy	X		X		X	X						
Additional Member Additional Organization Region Segment Selection															
1.	Doug Hils		RFC	1											
2.	Lee Schuster		FRCC	3											
3.	Dale Goodwine		SERC	5											
4.	Greg Cecil		RFC	6											
3.	Group	Russel Mountjoy	MRO NERC Standards Review Forum (NSRF)	X	X	X	X	X	X						
Additional Member Additional Organization Region Segment Selection															
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6											
2.	Chuck Lawrence	American Transmission Company	MRO	1											
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6											
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6											
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 5, 6											
6.	Jodi Jensen	Western Area Power Administration	MRO	1, 6											
7.	Joseph DePoorter	Madison Gas and Electric	MRO	3, 4, 5, 6											
8.	Ken Goldsmith	Alliant Energy	MRO	4											

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																		
			1	2	3	4	5	6	7	8	9	10									
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6																	
10.	Marie Knox	Midcontinent Independent System Operator	MRO	2																	
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6																	
12.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6																	
13.	Scott Nickels	Rochester Public Power District	MRO	4																	
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6																	
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6																	
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5																	
4.	Group	David Thorne	Pepco Holdings Inc & Affiliates			X		X													
Additional Member Additional Organization Region Segment Selection																					
1.	Carlton Bradshaw	Delmarva Power & Light Co	RFC	1, 3																	
2.	Carl Kinsley	Delmarva Power & Light Co	RFC	1, 3																	
5.	Group	Louis Slade	Dominion			X		X		X	X										
Additional Member Additional Organization Region Segment Selection																					
1.	Jeff Bailey	Nuclear		5																	
2.	Chip Humphrey	Power Generation	NPCC	5																	
3.	Michael Crowley	Electric Transmission	SERC	1, 3																	
4.	Sean Iseminger	Power Generation	RFC	5																	
5.	Connie Lowe	NERC Compliance Policy	SERC	1, 3, 5, 6																	
6.	Mike Garton	NERC Compliance Policy	NPCC	1, 3, 5, 6																	
7.	Randi Heise	NERC Compliance Policy	RFC	1, 3, 5, 6																	
8.	Rick Purdy	Electric Transmission	SERC	1, 3																	
6.	Group	David Greene	SERC Protection and Controls Subcommittee																		
Additional Member Additional Organization Region Segment Selection																					
1.	Paul Nauert	Ameren																			
2.	Bridget Coffman	Santee Cooper																			
3.	George Pitts	TVA																			
4.	Steve Edwards	Dominion VP																			
5.	Phil Winston	Southern Company Services																			
6.	David Greene	SERC																			

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Patrick Brown	North American Generator Forum Standards Review Team					X					
Additional Member		Additional Organization	Region	Segment Selection									
1.	Allen Schriver	NextEra Energy Resources	5										
2.	Steve Berger	PPL Susquehanna, LLC	5										
3.	Terry Crawley	Southern Company Generation	5										
4.	Pamela Dautel	IPR-GDF Suez Generation NA	5										
5.	Dan Duff	Liberty Electric Power	5										
6.	Mikhail Falkovich	PSEG	5										
7.	Gary Kruempel	MidAmerican Energy Company	5										
8.	Katie Legates	American Electric Power	5										
9.	Don Lock	PPL Generation, LLC	5										
10.	Joe O'Brien	NIPSCO	5										
11.	Chris Schaeffer	Duke Energy	5										
12.	Dana Showalter	E.ON Climate and Renewables	5										
13.	William Shultz	Southern Company	5										
14.	Mark Young	Tenaska, Inc.	5										
8.	Group	Terri Pyle	Oklahoma Gas & Electric	X		X		X	X				
Additional Member		Additional Organization	Region	Segment Selection									
1.	Terri Pyle	OG&E	SPP	1									
2.	Don Hargrove	OG&E	SPP	3									
3.	Leo Staples	OG&E	SPP	5									
4.	Jerry Nottmangel	OG&E	SPP	6									
9.	Group	Brent Ingebrigtsen	PPL NERC Registered Affiliates	X		X		X	X				
Additional Member		Additional Organization	Region	Segment Selection									
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1									
2.	Annette Bannon	PPL Susquehanna, LLC	RFC	5									
3.		PPL Montana, LLC	WECC	5									
4.		PPL Generation, LLC	RFC	5									
5.	Elizabeth Davis	PPL EnergPlus, LLC	NPCC	6									
6.			SERC	6									

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																	
			1	2	3	4	5	6	7	8	9	10								
7.		SPP	6																	
8.		MRO	6																	
9.		WECC	6																	
10.		RFC	6																	
10.	Group	Sasa Maljukan	Hydro One Networks Inc.	X		X														
Additional Member Additional Organization Region Segment Selection																				
1.	David Kiguel	Hydro One Networks Inc.	NPCC	1, 3																
2.	Paul Difilippo	Hydro One Networks Inc.	NPCC	1, 3																
11.	Group	Jason Marshall	ACES Standards Collaborators							X										
Additional Member Additional Organization Region Segment Selection																				
1.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5																
2.	John Shaver	Southwest Transmission Cooperative	WECC	1																
3.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5																
4.	Amber Anderson	East Kentucky Power Cooperative	SERC	1, 3, 5																
5.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5																
6.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4																
7.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1																
12.	Group	Robert Rhodes	SPP Standards Review Group		X															
Additional Member Additional Organization Region Segment Selection																				
1.	Timothy Bobb	Westar Energy	SPP	1, 3, 5, 6																
2.	John Boshears	City Utilities of Springfield	SPP	1, 4																
3.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5																
4.	Louis Guidry	Cleco Power, LLC	SPP	1, 3, 5																
5.	Jonathan Hayes	Southwest Power Pool	SPP	2																
6.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6																
7.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6																
8.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6																
9.	Wes Mizell	Westar Energy	SPP	1, 3, 5, 6																
10.	James Nail	City of Independence, MO	SPP	3																
11.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5																
12.	Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4																

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
13.	Group	Lloyd A. Linke	Western Area Power Administration	X					X					
Additional Member		Additional Organization	Region	Segment Selection										
1.	Upper Great Plains Region	Western Area Power Administration	MRO	1, 6										
2.	Rocky Mountain Region	Western Area Power Administration	WECC	1, 6										
3.	Sierra Nevada Region	Western Area Power Administration	WECC	1, 6										
4.	Desert South West Region	Western Area Power Administration	WECC	1, 6										
5.	Colorado Storage Project	Western Area Power Administration	WECC	6										
14.	Individual	Ryan Millard	PacifiCorp	X		X		X	X					
15.	Individual	Wayne Johnson	Southern Company	X		X		X	X					
16.	Individual	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X					
17.	Individual	Thomas Foltz	American Electric Power	X		X		X	X					
18.	Individual	Michelle D'Antuono	Occidental Chemical Corp. (Ingleside Cogeneration LP)					X						
19.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X					
20.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X					
21.	Individual	Alice Ireland	Xcel Energy	X		X		X	X					
22.	Individual	Daniel Duff	Liberty Electric Power					X						
23.	Individual	David Jendras	Ameren	X		X		X	X					
24.	Individual	Bill Fowler	City of Tallahassee			X								
25.	Individual	Michael Falvo	Independent Electricity System Operator		X									
26.	Individual	Gerald Farringer	Consumers Energy			X								
27.	Individual	Anthony Jablonski	ReliabilityFirst											X
28.	Individual	Tracy Goble	Consumers Energy Co.				X							
29.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X					
30.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X										
31.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X					
32.	Individual	Jonathan Meyer	Idaho Power Company	X										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
33.	Individual	Scott Langston	City of Tallahassee	X									
34.	Individual	Louis C. Guidry	Cleco	X		X		X	X				
35.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
36.	Individual	Brian Evans-Mongeon	Utility Services				X						
37.	Individual	Texas Reliability Entity, Inc.	Texas Reliability Entity, Inc.										X
38.	Individual	Bradley Collard	Oncor Electric Delivery Company LLC	X									
39.	Individual	Ryan Walter	Tri-State Generation and Transmission Association, Inc.	X		X		X					
40.	Individual	Michael P. Moltane	ITC	X									
41.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				

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

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
Consumers Energy Co.	Consumers Energy Co.
Hydro One Networks Inc.	IESO and NPCC RSC
Lincoln Electric System	MRO NERC Standards Review Forum (NSRF)
Utility Services	NPCC Reliability Standrds Committee
South Carolina Electric and Gas	SERC PCS
Kansas City Power & Light	SPP - Robert Rhodes
Ameren	We agree with the SERC Protection & Control Subcommittee (PCS) comments and include them by reference.

1. In response to comments, the drafting team revised the previously-posted draft of PRC-005-3 and the Supplementary Reference and FAQ document. Do you agree with these changes? If not, please provide specific suggestions for improvement.

Summary Consideration:

The drafting team made no changes to PRC-005-3.

Several comments were offered on PRC-005-2. The drafting team reminded the commenters that changes to previously-approved content in PRC-005-2 are out-of-scope and prohibited by the SAR for this project.

Several commenters objected to the inclusion of maintenance of Automatic Reclosing within a Reliability Standard. The drafting team explained that Automatic Reclosing is being added in response to a FERC directive from Order 758.

In response to comments regarding the objectives of PRC-005-3, the drafting team referred commenters to the referenced document, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012".

Several commenters requested an additional requirement be included in PRC-005-3 mandating that Balancing Authorities provide Transmission Owners, Generator Owners, and Distribution Providers the information identifying the current largest single generating unit in the Balancing Authority Area (described in Applicability 4.2.6), and notify those entities (within a specified time) when this information changes. The SAR for this project does not permit the addition of functional entities to the Applicability section of this standard; therefore, the drafting team is unable to make the requested change. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised.

In response to assorted comments regarding the Applicability 4.2.6 and the associated footnote, the drafting team added more discussion to the Supplementary Reference and FAQ document in Section 2.4.1.

Organization	Yes or No	Question 1 Comment
Oklahoma Gas & Electric	No	1. In the draft Standard and the Supplementary Reference and FAQ document, a lot of detail was deleted from the definition of Automatic Reclosing. The revised definition no longer includes the phrase "but excluding breaker internal controls such as anti-pump and various interlock circuits." Does this imply that those components

Organization	Yes or No	Question 1 Comment
		<p>are now included in the definition of Automatic Reclosing? In reference to these components, the Supplementary Reference and FAQ document (in section 15.8.1) states that, "These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4." The Standard needs to be explicit on what is and is not required to be tested as part of an entities PRC-005 maintenance and testing program rather than leaving it open to interpretation.</p> <p>2. In 4.2.6.1 of the Applicability section of the draft Standard, reference is made to the total installed gross generating capacity of a generating plant which is then compared to the gross generating capacity of the largest BES unit in the Balancing Authority Area. It would be helpful if the drafting team provided some examples (including some that references how to address combined cycle units/plants) in the Supplementary Reference document to help entities understand and properly apply Section 4.2.6.1 of the Standard.</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. The standard requires verification that Automatic Reclosing (defined as including two Components - the reclosing relay and the control circuitry associated with the reclosing relay), upon initiation, does not issue a premature closing command. All of the referenced components would be indirectly verified by performing the Automatic Reclosing control circuitry verification established in Table 4. 2. In response to your request, the drafting team provided additional discussion in Section 2.4.1 of the Supplementary Reference and FAQ document. 		
ACES Standards Collaborators	No	<p>(1) We find that the changes are non-substantive and do not present a problem. However, we continue to be concerned about modifying this standard when there is another version pending before the Commission. We believe it will only cause confusion. Given that this standard is historically one of the top ten most violated standards and the most violated non-CIP standard, industry does not need to be burdened with further confusion that will only cause additional violations. One</p>

Organization	Yes or No	Question 1 Comment
		<p>example of the confusion is the implementation plan of the proposed draft. If the PRC-005-2 standard was already enforceable, the implementation plan could focus only on auto-reclosing which would avoid the confusion.</p> <p>(2) Because there were no general feedback questions asked and there is no other appropriate question to place our other concerns with the proposed standard, we are inserting them here.</p> <p>(3) The implementation plan creates confusion with dual conflicting parallel dates. The confusion is understood by comparing PRC-005-2 implementation plan to the PRC-005-3 implementation plan. For example, the implementation plan for PRC-005-2 requires the responsible entity to be at least 30 percent compliant on the first day of the first calendar quarter 24 months following applicable regulatory approval for maintenance activities with a three year interval. The PRC-005-3 implementation plan is identical. Thus, if FERC approves PRC-005-2 such that it has an effective date of June 1, 2014, the responsible entity will have to be 30 percent compliant with R3 and R4 for equipment with three-year interval maintenance cycles by July 1, 2016. If FERC then approves PRC-005-3 such it has an enforceable date of September 1, 2015, the responsible entity will have to be 30 percent compliant with R3 and R4 for equipment with a three-year interval maintenance cycles by October 1, 2017. Thus, there will be two different conflicting dates for the 30 percent compliance level. Which applies? If the second applies, this is like resetting the compliance date. Furthermore, there is unnecessary confusion with the 30 percent compliant metric, as this could change from the two different implementation plans if additional equipment is installed during the implementation plan. There are too many compliance risks of having implementation plans overlapping or coming into effect in a short amount of time. This proposal mirrors the issues of the implementation plans with CIP version 4 and CIP version 5. FERC granted an extension in order to allow responsible entities to more efficiently utilize resources to transition to the next version. We, as an industry, should learn from this experience and not rush to the next version of the standard prematurely.</p>

Organization	Yes or No	Question 1 Comment
		<p>(4) We disagree with the statement (second paragraph first sentence and first bullet) in the general considerations section of the implementation plan that states the responsible entities must be prepared to identify Automatic Reclosing components during the transition from version 2 to version 3. While we agree that this ultimately will be necessary at some point in the transition to prepare for the compliance date, we are concerned that an auditor could interpret this implementation plan as requiring the responsible entity to develop an inventory of Automatic Reclosing components prior to the effective compliance date. A standard cannot retroactively require actions to be completed prior to its effective date. This identification of Automatic Reclosing components presents serious compliance issues and we recommend striking it in its entirety.</p> <p>(5) We disagree with the statement (second paragraph first sentence and second bullet) in the general considerations section of the implementation plan that states the responsible entities must be prepared to identify “whether each component has last been maintained according to PRC-005-2 (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof”. We do not have an issue if this statement applies only to the Protection System components because they have been under these standards for some time. However, this statement could be viewed as applying to Automatic Reclosing components and it should not because they have never been subject to any standard. While most responsible entities will have maintained their Automatic Reclosing components, they simply were not required to maintain them and, thus, the documentation may not be sufficient to demonstrate prior maintenance activities. Maintenance activities for Automatic Reclosing components are not required until PRC-005-3 is enforceable.</p> <p>(6) We do not understand why PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 will not be retired for 156 months or 13 years. That is quite a long time for these standards to be effective in parallel. This poses a potential for double jeopardy and we recommend retiring these standards at the same time the new standard becomes</p>

Organization	Yes or No	Question 1 Comment
		<p>enforceable.</p> <p>(7) We find the language in section 3 of the implementation plan for R3 and R4 confusing. That section proposes to require the responsible entity to comply with R3 and R4 for 30 percent of the Protection System components that are subject to three-year maintenance intervals. However, this language “or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage” is added as a caveat. We are unsure how to interpret it. Does this mean that if a generator has three-year maintenance interval that 30 percent of its Protection System components must meet compliance at the conclusion of the first succeeding maintenance outage or it is an exception and all of its Protection System components must meet R3 and R4 compliance obligations by the same date?</p> <p>(8) Section 4.2.6.1 of the applicability section of the standard is inconsistent with the proposed definition of the Bulk Electric System (BES) and may be inconsistent with existing definitions that vary by region. Since Inclusion I2 includes the generator and generator step up (GSU) transformer as part of the BES, what exactly would constitute the BES bus? The low side bus of the GSU transformer, the high side bus or some other location? All of these are part of the BES. This section needs further clarification.</p> <p>(9) Section 4.2.6.2 of the applicability section of the standard needs further refinement. What would constitute one bus away from the generating plant? What constitutes the plant? The electrical machine, turbine, GSU, and switchyard? What if there is more than one switchyard? What if the switchyard is not on the immediate property but short distance away? Some additional refinement would help to answer these questions. We suggest utilizing the GSU as demarcation point to help clarify.</p> <p>(10) The evidence retention section needs to clarify that the responsible entity is not required to keep “documentation of the two most recent performances of each distinct maintenance activity “during the initial implementation of the standard for Automatic Reclosing components. This clarification will help avoid the problems that</p>

Organization	Yes or No	Question 1 Comment
		<p>occurred with PRC-005-1 when auditors requested evidence from before the effective date of the requirements. The bottom line is that a standard cannot be retroactive and cannot compel evidence from before the effective date. This needs to be clear.</p> <p>(11) The evidence retention period is excessively long, is inconsistent with the Reliability Assurance Initiative (RAI), and is inconsistent with the Rules of Procedure. Since some Automatic Reclosing component maintenance intervals are 12 years, retaining the two most recent performances of each maintenance activity could result in evidence retention periods of almost 36 years. Entire careers will be worked before this evidence can be destroyed. Given the length of time, it is highly likely that responsible entities will lose some of the documentation which will result in paper violations that do nothing to support reliability. This is contrary to the RAI which is trying move to a forward looking compliance model that provides reasonable assurance of compliance. Furthermore, the evidence retention period is longer than the six year audit cycle for TOs, GOs, and DPs which is inconsistent with section 3.1.4.2 of Appendix C - Compliance Monitoring and Enforcement Program of the NERC Rules of Procedures. This section is very clear that the evidence retention cannot exceed a period prior to the last audit.</p> <p>(12) We suggest that Table 4-2(a) should be clarified that it only applies to those Automatic Reclosing components that are at large generator plants or close to large generator plants per applicability section 4.2.6.1 and 4.2.6.2 respectively. Otherwise, there may be confusion when compliance and enforcement personnel look at the table. They may view that it will apply to all Automatic Reclosing components that are not an integral part of a Special Protection System (SPS) including those are not close to large generators.</p>

Response: Thank you for your comments.

1. The drafting team is acting in accordance with the schedule NERC provided to FERC which outlines the timeframes in which NERC will respond to the directives of FERC Order 758 through the standards drafting process. Specifically regarding reclosing relays (Footnote 37), FERC directed NERC to: “By July 30, 2012, NERC should submit to the Commission either the completed project

Organization	Yes or No	Question 1 Comment
		<p>which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.” Providing the schedule for addressing both reclosing relays and relays that do not respond to electrical quantities addressed this requirement of FERC Order 758</p> <ol style="list-style-type: none"> 2. N/A 3. The implementation plan established under PRC-005-2 remains unchanged except for the addition of Automatic Reclosing Components required under PRC-005-3. The Implementation Plan provided with this posting is for PRC-005-3 and carries forward the implementation schedules contained in PRC-005-2. Compliance levels will be based upon applicable regulatory approvals of PRC-005-2 and PRC-005-3 and their associated applicable components. 4. Per the implementation period established for Requirement R1, an entity has 12 months to modify its Protection System Maintenance Program to include Automatic Reclosing and identify applicable Automatic Reclosing components. Identification of applicable Automatic Reclosing components is necessary to establish the maintenance schedules for implementing Requirements R3 and R4. The drafting team contends entities have sufficient time to establish a PSMP, identify the applicable components, and follow the Implementation Plan. 5. The entity should follow the previous maintenance intervals (if any) for any specific components until that component is addressed by PRC-005-3. As the transition is occurring, the entity should adjust its maintenance and testing schedules to demonstrate that the required percentage of components meets the maintenance intervals given in the PRC-005-3 tables at each of the percent compliant milestones given in its Implementation Plan. 6. For the Compliance Enforcement Authority to be assured of compliance, the drafting team contends that the Compliance Enforcement Authority will need the data of the most recent performance of the maintenance, as well as the data of the preceding one to validate that entities have been in compliance since the last audit (or currently since the beginning of mandatory compliance). The retirement schedule of the aforementioned standards meets this intent. 7. For Requirements R3 and R4, generating plants with scheduled outage intervals exceeding two years must be 30% compliant at the conclusion of the first maintenance outage. It should be noted that this extension does not apply for the 60% and 100% thresholds. 8. The BES is a NERC defined term that is undergoing revisions and might contain regional variations. PRC-005-3 will be workable regardless of how the BES is defined. If an element is a BES element and is located at a generating plant substation, it is included per Section 4.2.6.1, and the requirements for Automatic Reclosing apply. See Section 2.4.1 in the Supplementary Reference and FAQ document for more discussion. 9. The drafting team contends Applicability Section 4.2.6.2 is clear and is based upon the recommendations from the SAMS/SPCS report. See Section 2.4.1 in the Supplementary Reference and FAQ document for more discussion.

Organization	Yes or No	Question 1 Comment
		<p>10. From the Implementation Plan, General Considerations: “For activities being added to an entity’s program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.” The Evidence Retention section of the standard applies to steady-state performance of the standard after implementation.</p> <p>11. For the Compliance Enforcement Authority to be assured of compliance, the drafting team contends that the Compliance Enforcement Authority will need the data of the most recent performance of the maintenance, as well as the data of the preceding one to validate that entities have been in compliance since the last audit (or currently since the beginning of mandatory compliance). The drafting team has specified the data retention in the posted standard to establish this level of documentation. This seems to be consistent with what auditors are expecting (per the drafting team’s experience), and is also consistent with Compliance Process Bulletins 2011-001 and 2009-05. The entity is urged to assure that data is retained as specified within the standard.</p> <p>12. The drafting team contends the standard is clear in that the tables apply to only those components contained in Section 4.2 Facilities.</p>
PPL NERC Registered Affiliates	No	<p>1) There are currently two NERC approved projects filed at FERC (PRC-005-1.1b and PRC-005-2). NERC should consider waiting to proceed with this project until the current projects are ruled on and FERC provides further direction.</p> <p>2) For 4.2.6, for reclosing capability, it is unclear what functionality is to be tested. Please define.</p> <p>3) For PRC-005-3 section 4.2.6.2, please provide the technical basis for this application of the Standard. Specifically, this application states for Automatic Reclosing: “Applied on 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.” Please provide the technical basis/reasoning for the 10-mile criteria. At a recent North American Transmission Forum Workshop on Protection System Maintenance Program it was implied that the 10 mile rule is for cases where a generator has a short connection to another company’s substation. Please clarify if this is the case.</p> <p>4) For PRC-005-3 section R1, consider adding the following language that is used for</p>

Organization	Yes or No	Question 1 Comment
		<p>PRC-005-1.1b “each Generator Owner that owns a generation or generator interconnection Facility Protection System...” This is NERC-approved language that has been through the standards development process and has technical justification through Project 2010-07.</p> <p>5) Please provide the technical basis for R1.1 which requires battery testing for DC Supply Component Type Protection Systems to be time based.</p> <p>6) Table 1-2 of PRC-005-3 requires functional testing of non-monitored communication systems on a 4 month cycle. Please specify NERC’s criteria for the functional testing (what attributes to be tested). Additionally, specifically define monitoring criteria and data intervals for continuous monitoring of communications systems (to see if check back (fail/no fail) monitoring is adequate).</p> <p>7) This standard presents compliance documentation uncertainties for applicable reclosing relays defined in Applicability Section 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”. This standard now assumes that GO/TOs are going to coordinate and document that they have contacted the BA to determine the largest unit in the area and then determine if the reclosing relays are/are not applicable but does not mention it in the measures. How much coordination and documentation is required by a GO and its associated switchyards. Does the TO need to prove that the generation facility does or does not exceed the largest BES unit? Does this become part of a PRC-001 requirement to coordinate protection systems?</p>

Response: Thank you for your comments.

- 1) The drafting team is acting in accordance with the schedule NERC provided to FERC which outlines the timeframes in which NERC will respond to the directives of FERC Order 758 through the standards drafting process.
- 2) This is defined in the PRC-005-3 tables 4-1, 4-2a, and 4-2b of the proposed standard and clarified in the reference document "Considerations for the Maintenance and Testing of Autoreclosing Schemes."

Organization	Yes or No	Question 1 Comment
		<p>3) As noted in the SAMS and SPCS study, premature autoreclosing has the potential to cause generating unit or plant shaft damage or instability. The report noted that "transmission line impedance on the order of 1 mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin."</p> <p>4) Your comment refers to previously-approved content. The SAR for this project explicitly limits the scope of this project to those changes needed to address Automatic Reclosing. Changes such as you suggest are out-of-scope.</p> <p>5) Your comment refers to previously-approved content. The SAR for this project explicitly limits the scope of this project to those changes needed to address Automatic Reclosing. These requirements are unchanged from PRC-005-2 and specific maintenance practices and criteria are discussed in the Supplementary Reference and FAQ document for PRC-005-2.</p> <p>6) Your comment refers to previously-approved content. The SAR for this project explicitly limits the scope of this project to those changes needed to address Automatic Reclosing. These requirements are unchanged from PRC-005-2 and specific maintenance practices and criteria are discussed in the Supplementary Reference and FAQ document for PRC-005-2.</p> <p>7) The addition of a functional entity to the Applicability section of the standard is outside the scope of the SAR for this project. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised.</p>
Pepco Holdings Inc & Affiliates	No	<p>1) In section 4.2.6.1 the term "gross generating plant capacity" is used. We assume this refers to nameplate MVA ratings. To avoid confusion as to what unit of capacity (MVA or MW) is to be used to evaluate these criteria we suggest the phrase be clarified as "gross generating plant capacity (in MVA)".</p> <p>2) NERC's System Analysis and Modeling Subcommittee (SAMS) recommended limiting the applicability of automatic reclosing within this standard to only those installations that would impact the reliability of the BES. Section 4.2.6.1 uses criteria based on the "gross generating plant capacity". Neither the PRC-005-3 standard itself, nor the Supplementary Reference and FAQ document explains how to calculate this gross capacity number. Consider a generating plant that has a total of 600 MVA of installed capacity connected to a 230kV bus. There are also units within the same "power plant" with 200 MVA of capacity connected to a 69kV bus. The 230kV and 69kV busses are interconnected by an autotransformer. The "gross generating plant capacity" is 800 MVA, however 200 MVA of this is connected below 100kV and is not</p>

Organization	Yes or No	Question 1 Comment
		<p>considered BES generation. If it is not considered BES generation, then it should be excluded from the calculation of gross plant capacity in Section 4.2.6.1, as the loss of this generation would not directly affect the reliability of the BES.</p> <p>3) In some switchyard arrangements generating units within the same power plant are connected to separate switchyard busses that are not connected together. This may be done for reliability reasons and to control fault current levels. In these situations, the calculation of gross plant capacity in Section 4.2.6.1 should be based only on the amount of generation directly connected to the individual bus, and not the total amount in the plant.</p> <p>4) The NERC SAMS review concluded that automatic reclosing mal-performance affects BES reliability when “inadvertent reclosing near a generating station subjects the generation station to severe fault stresses”. The concern appears to be potential shaft torque damage, or instability, of rotating machines to automatic reclosing mal-performance. That being the case, generation sources that are not subject to severe fault stresses, such as inverter based generation, or static reactive sources (SVC’s, capacitor banks, etc.) should not be included in the calculation of gross plant capacity. However, since synchronous condensers are subject to the same fault stresses as synchronous generators they should probably be included in the gross plant generation calculation, providing they are interconnected at 100kV, or above.</p> <p>5) To adequately address the concerns raised in the above sets of comments we suggest Section 4.2.6.1 be re-worded as follows to provide clarity and eliminate confusion on how to evaluate this plant capacity calculation: “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 (in MVA) connected to that bus is greater than the gross capacity (in MVA) of the largest BES generating unit within the Balancing Authority Area.” In addition, a qualifying footnote defining “gross generating plant capacity” needs to be added as follows: “For application of 4.2.6.1 gross generating plant capacity is defined as the sum total of the nameplate ratings, expressed in MVA, of all BES rotating machine generating</p>

Organization	Yes or No	Question 1 Comment
		<p>units (including synchronous condensers) that are connected to a common BES switchyard bus.” Also, specific examples showing how to calculate “gross generating capacity” should be included in the Supplemental Reference document in order to illustrate and clarify the issues described in the above comments. How will the applicable functional entities be aware of the largest (or change in the largest) BES generating unit within the BA area?</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1) Thank you for your comments. No change was made to the standard; however, the drafting team provided additional discussion in Section 2.4.1 of the Supplementary Reference and FAQ document. 2) The intent was to prevent a loss of generation that exceeds the capacity of the largest unit in the Balancing Authority Area regardless of the connected voltage levels. There are numerous scenarios possible and the drafting team contends that if the resolution of a particular scenario isn’t clear from the Applicability Section, an entity should either maintain the Automatic Reclosing pursuant to PRC-005-3 or perform studies to exclude the Automatic Reclosing maintenance (reference the footnote in the Applicability Section). 3) There are numerous scenarios possible and the drafting team contends that if the resolution of a particular scenario isn’t clear from the Applicability Section, an entity should either maintain the Automatic Reclosing pursuant to PRC-005-3 or perform studies to exclude the Automatic Reclosing maintenance (reference the footnote in the Applicability Section). 4) Damage to a generator is not the basis for determining the applicability of the Automatic Reclosing components; the loss of generation capacity that exceeds the largest unit within the Balancing Authority Area is the basis. Since there are numerous scenarios possible, the drafting team contends that if the resolution of a particular scenario isn’t clear from the Applicability Section, an entity should either maintain the Automatic Reclosing pursuant to PRC-005-3 or perform studies to exclude the Automatic Reclosing maintenance (reference the footnote in the Applicability Section). 5) An entity is expected to coordinate with its Balancing Authority and agree on the unit of measure (MVA or MW) of the generation facilities – consistency is required. Entities are required to remain compliant and to obtain the data necessary to meet requirements. 		
Southern Company	No	<ol style="list-style-type: none"> 1) We believe that there should be a Requirement for the BA to initially inform the TOs and GOs in their area which units are in scope. Minimally, there must be a requirement that the BA identify the ‘largest BES generating unit’ and inform all the

Organization	Yes or No	Question 1 Comment
		<p>TOs and GOs in their area.</p> <p>2)Secondly, related to 1) above, there must be a requirement that the BA inform all the TOs and GOs in their area when a change occurs related to the ‘largest BES generating unit’.</p>
<p>Response: Thank you for your comments.</p> <p>1 & 2) The addition of a functional entity to the Applicability section of the standard is outside the scope of the SAR for this project. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised.</p>		
Colorado Springs Utilities	No	<p>1.Concerning facilities, would a reliability based method of determining covered facilities more likely better serve the reliability of the BES versus the generation based cap method under 4.2.6?</p> <p>2.With no standard requiring re-closing relaying be in place, there will be a tendency to disable all re-closing relays to avoid facilities coming under this standard.</p>
<p>Response: Thank you for your comments.</p> <p>1) The drafting team is following the recommendations provided by the technical experts on the NERC System Analysis and Modeling Subcommittee and the System Protection and Control Subcommittee. They issued a joint technical document entitled “Considerations for Maintenance and Testing of Autoreclosing Schemes” and it is posted on the PRC-005-3 project page for your review.</p> <p>2) The drafting team is responding to a FERC directive to include Automatic Reclosing in the maintenance standard.</p>		
ITC	No	<p>1. 4.2.6 references a footnote 1 that is an exclusion. How can an exclusion be put into a footnote? It should be up in the standard, not in a footnote.</p> <p>2. Regarding 4.2.6.1 for generating plant substations that have generator outputs at separate kV levels where the switchyards are not normally tied together are they treated as separate generating plants? Same question for locations that have</p>

Organization	Yes or No	Question 1 Comment
		<p>generator outputs where the switchyards are not directly tied together.</p> <p>3. For a location that has a couple Balancing Authority Areas over it is the largest BES generating unit determined by the largest Balancing Authority Area?</p>
<p>Response: Thank you for your comments.</p> <p>1) The footnote is part of the Applicability section of the standard.</p> <p>2) There are numerous scenarios possible and the drafting team contends that if the resolution of a particular scenario isn't clear from the Applicability Section, an entity should either maintain the Automatic Reclosing pursuant to PRC-005-3 or perform studies to exclude the Automatic Reclosing maintenance (reference the footnote in the Applicability Section).</p> <p>3) Coordinated operations between Transmission Owners and Generator Owners and their associated Balancing Authorities are required under other NERC Reliability Standards – TOP-002-2.1b. Entities are required to remain compliant and to obtain the data necessary to meet requirements.</p>		
Liberty Electric Power	No	<ol style="list-style-type: none"> 1. 4.2.6.1 uses the phrase "greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area" as one determinant for inclusion of relays into the standard. However, generators do not have a wide area view of the system, and cannot determine the gross capacity of the largest BES generating unit. Does this value include all generation which could trip simultaneously at a single generating location? All generation which is connected through a single step-up transformer? Further, changes outside of the control of a generator could move relays in or out of the program. If retirement of an asset lowers the gross capacity value of the largest BES generating unit, would relays immediately be pulled into the program? 2. Finally, there is no requirement for the BA to provide the gross capacity value to generation owners. The BA should be added to the list of covered entities, with a requirement to provide to all entities in their balancing area notice of the gross capacity of the largest generating unit once per calendar year, and within 30 days of a change in this value. 3. Another section should be added to the standard to list the implementation requirements for existing assets when a covered relay enters the program.

Organization	Yes or No	Question 1 Comment
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. There are numerous scenarios possible and the drafting team contends that if the resolution of a particular scenario isn't clear from the Applicability Section, an entity should either maintain the Automatic Reclosing pursuant to PRC-005-3 or perform studies to exclude the Automatic Reclosing maintenance (reference the footnote in the Applicability Section). 2. The addition of a functional entity to the Applicability section of the standard is outside the scope of the SAR for this project. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised. 3. The drafting team incorporated the revised "Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area" into the body of the full Implementation Plan such that only a single Implementation Plan now exists. 		
Manitoba Hydro	No	<p>Although Manitoba Hydro will continue to maintain our "negative" vote for this standard based on concerns from the PRC-005-2 version, we do offer the following comments to the drafting team in regards to PRC-005-3:</p> <p>(1) Table 1-4(a), (c), (f) - Manitoba Hydro suggests that the maintenance activity for electrolyte level inspections would be more appropriately specified on intervals of six calendar months, rather than on a four month basis. It is our experience that maximum maintenance intervals of 6 months are adequate at addressing reliability. Requiring four month intervals would be needlessly burdensome to industry without achieving additional reliability benefit. Moreover, the maintenance activities which require inspections to be completed every 18 months will oblige entities to make an additional site visit every second year. In effect, entities are being asked to check equipment (e.g. electrolyte levels) on month 16, return on month 18 to check equipment components such as ohmic values, charge float voltage, etc, and then required to return again on month 20 to check electrolyte levels, which is excessive. Instead, Manitoba Hydro suggests a more manageable maximum maintenance interval of 4 calendar months for these types of maintenance activities (station dc supply voltage, electrolyte level and for unintentional grounds).</p>

Organization	Yes or No	Question 1 Comment
<p>Response: Thank you for your comment.</p> <p>Your comment refers to previously-approved content. The SAR for this project explicitly limits the scope of this project to those changes needed to address Automatic Reclosing and prohibits other changes as you suggest. The requirements are unchanged from PRC-005-2. Specific maintenance practices and criteria are discussed in the Supplementary Reference and FAQ document.</p>		
<p>Public Service Enterprise Group</p>	<p>No</p>	<p>Automatic reclosing systems, except for those which are an integral part of an SPS, are not part of Protection Systems that are designed and installed to detect and protect the BES from damage from faults and to keep blackouts localized, i.e., prevent cascades. Autoreclosing relays and systems are installed simply to automate an action by a system operator to close a breaker which automatically tripped, and with one specific possible exception, contribute very little to BES reliability. Besides the SPS, the one possible exception may be in those areas where by virtue of the transmission system configuration rapid reclosing of a tripped breaker is needed to minimize stability issues. PSEG agrees that reclosing relays may be significant to that specific circumstance, i.e., where rapid action is needed to avoid system instability. To identify those specific locations and circumstances and limit the inclusion of such relays to those where it is necessary, PSEG suggests that the drafting team incorporate language similar to that in the Transmission Relay Loadability Standard PRC-023-2 R6 which could be modified for PRC-005-3 to read as follows: “Each Planning Coordinator shall conduct an annual assessment to determine the specific locations/circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers with automatic reclosing relays must comply with the maintenance and testing requirements for such relays under this standard.” The Planning Coordinator has the expertise and skills to make this determination; many if not most BES asset owners do not. Power systems are designed to deal with permanent faults, not temporary faults. The extra cost of inclusion of many automatic reclosing relays in the maintenance and testing program would yield little or no benefit to reliability of the BES. Only those defined as essential by the Planning Coordinator should be included in this Standard.</p>

Organization	Yes or No	Question 1 Comment
<p>Response: Thank you for your comments.</p> <p>FERC Order 758 directed that maintenance of reclosing relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive and when approved, will supersede PRC-005-2. Furthermore, PRC-005-3 follows the recommendations included in the SAMS/SPCS technical document “Considerations for Maintenance and Testing of Autoreclosing Schemes.”</p>		
Consumers Energy	No	<p>Consumer’s Energy Ballot member is voting NEGATIVE on Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) PRC-005-3 since the standard does not address how each entity is expected to obtain the required information “the gross capacity of the largest BES generating unit with the Balancing Authority Area” (in section 4.2.6.1) and know when it changes.</p>
<p>Response: Thank you for your comments.</p> <p>The addition of a functional entity to the Applicability section of the standard is outside the scope of the SAR for this project. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised.</p>		
Consumers Energy Co.	No	<p>Consumer’s Energy Ballot member is voting NEGATIVE on Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) PRC-005-3 since the standard does not address how each entity is expected to obtain the required information “the gross capacity of the largest BES generating unit with the Balancing Authority Area” (in section 4.2.6.1) and know when it changes.</p>
<p>Response: Thank you for your comments.</p> <p>The addition of a functional entity to the Applicability section of the standard is outside the scope of the SAR for this project. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised.</p>		

Organization	Yes or No	Question 1 Comment
Western Area Power Administration	No	<ol style="list-style-type: none"> 1. Further clarification and definition is required regarding the application of the standard to “premature” closing. Specifically, what is the definition of “premature” and why does the standard not refer to inadvertent or incorrect auto reclosing. 2. Facilities Section 4.2.6.2 applies to 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. This Section should be clarified and should not include BES elements at those substations connected at a different voltage than the incoming generation circuit. The impedance of any transformation should represent sufficient isolation. 3. It should be clarified that dc control circuitry and power circuit breaker close coils are only included with automatic reclosing that is an integral part of a SPS.
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. “Premature” means “occurring or existing before the normal or expected time”. The concern from the SAMS report is in regard to premature reclosing, not lack of reclosing or reclosing with longer than designed setting timeframe. 2. The drafting team followed the recommendations included in the “Considerations for Maintenance and Testing of Autoreclosing Schemes” and has provided additional language in the Supplementary Reference and FAQ document in Section 2.4.1. There are numerous scenarios possible and the drafting team contends that if the resolution of a particular scenario isn’t clear from the Applicability Section, an entity should either maintain the Automatic Reclosing pursuant to PRC-005-3 or perform studies to exclude the Automatic Reclosing maintenance (reference the footnote in the Applicability Section). 3. The drafting team contends that Tables 4-2(a) and 4-2(b) are clear: The control circuitry up to and including the close coil is included for circuit breakers involved in SPS schemes (Table 4-2(b)). If not part of an SPS, it is only necessary to verify that the control circuitry does not cause a premature close (Table 4-2(a)). 		
SPP Standards Review Group	No	<ol style="list-style-type: none"> 1. In the definition of Automatic Reclosing a goodly amount of detail has been deleted from the definition. Does the excluded portion of the definition, specifically breaker internal controls such as anti-pump and various interlock circuits still fall under the standard? The reference document implies that they do,

Organization	Yes or No	Question 1 Comment
		<p>but the revised wording is not clear to us.</p> <ol style="list-style-type: none"> 2. In 4.2.6.1 reference is made to the total installed gross generating capacity of a generating plant which is then compared to the gross generating capacity of the largest BES unit in the Balancing Authority Area. Shouldn't the reference to the largest unit also state the installed gross capacity of the unit to prevent any confusion? Also, in selecting to use gross generation numbers, we wonder if consideration was given to generation values used in other standards such as BAL-002 and BAL-003 which tend to lean toward net generation values rather than gross. 3. In the Supplementary Reference and FAQ document we suggest replacing the term 'supervisor' on Page 92 in Section 15.8.1 FAQ in the 7th line of the 1st paragraph in the response to the 2nd question with 'supervision'. The sentence would then read '...applicability of associated supervision/conditional logic and the...'.
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. The standard requires verification that Automatic Reclosing (defined as including two Components a) Reclosing relay and b) Control circuitry associated with the reclosing relay) upon initiation, does not issue a premature closing command. All of the components mentioned would be indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4. 2. The Applicability section 4.2.6.1 is consistent with the recommendations from the SAMS/SPCS report. See Section 2.4.1 in the Supplementary Reference and FAQ document for more discussion. An entity is expected to coordinate with its Balancing Authority and agree on the unit of measure (MVA or MW) of the generation facilities – consistency is required. 3. The drafting team made the suggested change. 		
MRO NERC Standards Review Forum (NSRF)	No	<ol style="list-style-type: none"> 1. Please clarify what is meant by "BES elements at substations one bus away from generating plants". How is the one bus criterion applied at a generating station with power transformation and multiple voltages? The use of the words substation and "one bus away" leaves the definition open to interpretation when a plant is connected at one voltage class and there are reclosing relays at another voltage class. The higher or lower voltage class bus could be read as "one bus away" and

Organization	Yes or No	Question 1 Comment
		<p>yet at the same substation. It may be necessary to speak in terms of either substations or electrical busses. It may also be necessary to define how a different voltage class bus should be treated. Could a large power transformer between voltage classes be equivalent to 10 circuit miles of impedance? Was the reclosing only meant to apply at the same voltage class?</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team followed the recommendation of the “Considerations for Maintenance and Testing of Autoreclosing Schemes” and has provided additional language in the Supplementary Reference and FAQ document in Section 2.4.1. There are numerous scenarios possible and the drafting team contends that if the resolution of a particular scenario isn’t clear from the Applicability Section, an entity should either maintain the Automatic Reclosing pursuant to PRC-005-3 or perform studies to exclude the Automatic Reclosing maintenance (reference the footnote in the Applicability Section).</p>		
American Electric Power	No	<p>Regarding 4.2.6.2 in the Facilities section, the verbiage used suggests that substations that are one bus away, but connected by a transformer instead of a line, would be in scope. This would seem technically inappropriate, as a transformer would typically have a higher impedance than 10 miles of line and therefore premature reclosing at these substations should not affect generators one bus away in these cases. If such substations were to be included, it would unnecessarily bring into scope many more reclosing relays than intended by FERC Order No. 758.AEP envisions voting affirmative on this proposed standard if our concerns regarding scope are eventually addressed.</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team followed the recommendation of the “Considerations for Maintenance and Testing of Autoreclosing Schemes” and has provided additional language in the Supplementary Reference and FAQ document in Section 2.4.1. There are numerous scenarios possible and the drafting team contends that if the resolution of a particular scenario isn’t clear from the Applicability Section, an entity should either maintain the Automatic Reclosing pursuant to PRC-005-3 or perform studies to exclude the Automatic Reclosing maintenance (reference the footnote in the Applicability Section).</p>		
Independent Electricity System	No	<p>The IESO contends that the analysis required by the Footnote 1 is out of the scope of</p>

Organization	Yes or No	Question 1 Comment
Operator		<p>PRC-005-3, which is to document programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the BES so that they are kept in working order. In addition, the analysis required by the Footnote 1 is vague and difficult to assess compliance. In the IESO's view, contingencies and related tests performed in transient simulations should be defined in the planning standards (eg. the TPL standards), instead of PRC-005-3 which is drafted for maintenance purposes. We suggest removing the Footnote 1 from the draft standard, or in case it is retained it should be revised to address the aforementioned concerns.</p>
<p>Response: Thank you for your comments.</p> <p>The information contained within the footnote is to allow the responsible entity to determine which reclosing systems they may exclude. The data required to determine exclusion is to be obtained by the owner. It is the responsibility of the Transmission Owner, Generator Owner, and Distribution Provider with Automatic Reclosing to apply the standard and to perform the necessary evaluations to exclude otherwise-applicable Automatic Reclosing from their PSMP if they desire to do so.</p>		
Dominion	No	<p>The drafting team did not address concerns relative to how an entity could determine the gross capacity of the largest BES generating unit within the Balancing Authority Area. Dominion suggests the drafting team include a requirement that the BA post or make such information available to all entities in its area. The drafting team did not address concerns that only planning entities are typically afforded access to the models or information, or have the technical skills necessary to be able to make the determination necessary to allow the exclusion included in footnote 1.</p>
<p>Response: Thank you for your comments.</p> <p>The addition of a functional entity to the Applicability section of the standard is outside the scope of the SAR for this project. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised.</p>		
American Transmission	No	<p>The selection criteria proposed to identify the reclosing relays that affect the</p>

Organization	Yes or No	Question 1 Comment
Company, LLC		reliability of the Bulk Electric System remains unclear. Please clarify what is meant by “BES elements at substations one bus away from generating plants”. How is the one bus criterion applied at a generating station with power transformation and multiple voltages?
<p>Response: Thank you for your comments.</p> <p>The drafting team followed the recommendation of the “Considerations for Maintenance and Testing of Autoreclosing Schemes” and has provided additional language in the Supplementary Reference and FAQ document in Section 2.4.1. There are numerous scenarios possible and the drafting team contends that if the resolution of a particular scenario isn’t clear from the Applicability Section, an entity should either maintain the Automatic Reclosing pursuant to PRC-005-3 or perform studies to exclude the Automatic Reclosing maintenance (reference the footnote in the Applicability Section).</p>		
North American Generator Forum Standards Review Team	No	This standard presents compliance documentation uncertainties for applicable reclosing relays defined in Applicability Section 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”. This standard now assumes that GO/TOs are going to coordinate and document that they have contacted the BA to determine the largest unit in the area and then determine if the reclosing relays are/are not applicable but does not mention it in the measures. How much coordination and documentation is required by a GO and its associated SWYDs TO to prove that the generation facility does or does not exceed the largest BES unit? Does this become part of a PRC-001 requirement to coordinate protection systems?
<p>Response: Thank you for your comments.</p> <p>The addition of a functional entity to the Applicability section of the standard is outside the scope of the SAR for this project. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised.</p>		

Organization	Yes or No	Question 1 Comment
Tri-State Generation and Transmission Association, Inc.	No	<ol style="list-style-type: none"> 1. Tri-State Generation and Transmission Association, Inc. finds that Table 4-1 is too inclusive and should include a restriction for only automatic reclose relays/functions that are required for system stability, with a list of which those should be as per SAMS, such as SPS and near generation. Table 4-1, as written, captures more equipment than is necessary, creating an undue administrative burden with little, to no, benefit to the reliability of the BES. Adding a compliance liability for reclosing relays that do not impact system stability could lead to industry removing many of the reclosing relays used for expeditious restoration. This does not improve system reliability. Also, since the majority of reclosing functions utilizing microprocessor relays reside within the microprocessor protective relay, the documentation for this testing will be included within documentation already required and provided under Table 1-1. To provide a separate list and documentation for all BES microprocessor reclosing functions will create an undue administrative burden on industry with little to no value to the BES. Further, we recommend the applicability of reclosers is changed to “reclosers identified by the entity’s selection criteria to be critical to the operation of the BES per its Maintenance and Testing Program” to better align with FERC order 758 where FERC recommends “selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System”. 2. Tri-State suggests that Table 4-2(a), Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS, be removed in its entirety or a maintenance activity specific to the circuitry be defined. The maintenance activity required in Table 4-2(a) is not a maintenance activity that verifies the control CIRCUITRY. A close “command” is external to the hardware circuitry. Whether or not that command occurs, does not confirm the functionality of the close circuitry hardware. The timing test for a reclosing function is also usually included within the testing of the protective relay, which is part of Table 1-1 and Table 4-1, making this table slightly redundant to what already exists. A definition of “premature”, giving specific tolerances, will also be required, if kept within the text, to understand at what point a test would fail or a result would be viewed as “non-

Organization	Yes or No	Question 1 Comment
		<p>compliant". Any test for a microprocessor instantaneous reclose would fail this requirement, as the close command is already present at the beginning of the sequence, hence being "premature". A PASS test result showing the reclose command was initiated within the tolerance of the relay but prior to the setting could be viewed as "premature" and be interpreted as "non-compliant". A FAIL test result showing the relay closed well out of the manufacturer tolerance but after the setting would be viewed as "compliant". If the text and Table remain, the statement: "Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry" should be changed to, "Verify that the close circuitry operates per engineering settings, and not sooner than (tolerance) of the setting."</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. The drafting team followed the recommendations included in the SAMS/SPCS technical document "Considerations for Maintenance and Testing of Autoreclosing Schemes" for determining the applicable reclosing relays. 2. The drafting team contends that Tables 4-2(a) and 4-2(b) are clear: The control circuitry up to and including the close coil is included for circuit breakers involved in SPS schemes (Table 4-2(b)). If not part of an SPS, it is only necessary to verify that the control circuitry does not cause a premature close (Table 4-2(a)). 		
Cleco	No	<p>We do not believe reclosing relays are protective devices and therefore are not subject to this level of oversight. Second, the strongest justification was that if the relay failed to operate correctly and reclosed instantaneously, the generator would be subject to additional fault duty. We have not seen such a failure and do not see the justification for including reclosing relays or restoration devices in a Protection System Maintenance & Testing Standard. Major storm events near the station or breakers failing to latch are far more likely to cause sequential faults.</p>
<p>Response: Thank you for your comments.</p> <p>FERC Order 758 directed that maintenance of reclosing relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive, and follows the recommendations included in the SAMS/SPCS technical document</p>		

Organization	Yes or No	Question 1 Comment
"Considerations for Maintenance and Testing of Autoreclosing Schemes."		
Texas Reliability Entity, Inc.	No	<p>We feel that the proposed maintenance activities in tables 4-1 and 4-2 do not necessarily address all of the typical failure modes of reclosing relays and control circuitry associated with them and offer the following comments:</p> <p>1) Definition of Automatic Reclosing: Is it the drafting team’s intention that “Control circuitry associated with the reclosing relay” includes a separate sync check relay that may be used in the reclosing scheme? The definition is not clear and the drafting team may want to clarify.</p> <p>2) Table 1-3: The drafting team may want to consider adding an activity to verify voltage signals are provided for reclosing relay sync check functions.</p> <p>3) Table 4-2(a) and 4-2(b): The drafting team may want to consider including activities to verify that auxiliary relays in the reclosing scheme (i.e. bus differential or breaker failure lockout relays) properly inhibit reclosing. The drafting team may also want to consider including activities to verify sync check functions depending on the system design (i.e. hot bus-hot line, hot bus-dead line, etc.). These two activities are necessary to verify that the reclosing scheme will not issue a reclose signal when it is not desired. Table 4-2(b): Suggest rewording the 2nd block to say “Verify all paths of the control circuits ***including all auxiliary relays*** associated with Automatic Reclosing...”</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> The drafting team contends that Tables 4-2(a) and 4-2(b) are clear: The control circuitry up to and including the close coil is included for circuit breakers involved in SPS schemes (Table 4-2(b)). If not part of an SPS, it is only necessary to verify that the control circuitry does not cause a premature close (Table 4-2(a)). Sync check relays are not in scope of PRC-005-03. See the SAMS/SPCS report. The drafting team is following the recommendations provided by the technical experts on the NERC System Analysis and Modeling Subcommittee and the System Protection and Control Subcommittee. They issued a joint technical document entitled “Considerations for Maintenance and Testing of Autoreclosing Schemes” and it is posted on the PRC-005-3 project page for your 		

Organization	Yes or No	Question 1 Comment
review.		
SERC Protection and Controls Subcommittee	Yes	<p>1) Please provide FAQ examples to clarify the meaning of ‘total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit’. Our take is the gross MVA for FAC-008 would be appropriate. But there are several MOD standards, including some pending FERC approval, that will prove MW and MVAR ‘capability’ not ‘capacity’.</p> <p>2) We request that the drafting team modify the FAQ 2.4.1 to include “typically IEEE Device No. 79” in referring to the Automatic Reclosing relay because this helps clarify the scope. Begin the answer with “Yes. Automatic Reclosing includes reclosing relays (typically IEEE Device No. 79) and the associated dc control circuitry.”</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> In response to your request, the drafting team provided additional discussion in Section 2.4.1 of the Supplementary Reference and FAQ document. Automatic Reclosing may be either a function imbedded in other devices or a stand-alone device. The drafting team does not believe that the IEEE function number should be referenced. 		
Tacoma Power	Yes	<p>Additional Comments-</p> <ol style="list-style-type: none"> In the definition of a PSMP, capitalize ‘components’. In the definition of a PSMP (including Supplementary Reference and FAQ document), capitalize ‘automatic reclosing’. In the Implementation Plan, change “The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of first calendar quarter...” to “The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter...”
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> The drafting team cannot capitalize “components” in the definition of Protection System Maintenance Program (PSMP) because 		

Organization	Yes or No	Question 1 Comment
<p>PSMP is a NERC Glossary Term.</p> <p>2. The drafting team cannot capitalize “automatic reclosing” in the definition of Protection System Maintenance Program (PSMP) because PSMP is a NERC Glossary Term.</p> <p>3. The drafting team made the suggested addition.</p>		
<p>Duke Energy</p>	<p>Yes</p>	<ol style="list-style-type: none"> 1. Duke Energy requests additional information regarding the Footnote 1 exclusion provision. As written, it is unclear as to what exactly is needed to provide demonstration for this provision, as well as the frequency of the demonstration necessary to remain compliant. For example, if an entity performs an analysis to prove that the exclusion was applicable to a specific Automatic Reclosing Relay, would the entity need to run another analysis ever again, or would an analysis only need to be done if there was a change to the Balancing Authority Area’s system or the BES? 2. Also Duke Energy suggests that because Footnote 1 effectively acts as an exclusion, that the drafting team consider placing the Footnote in the standard itself.
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. The drafting team contends that a dynamic study of some sort would be necessary to demonstrate the exclusion of the automatic relaying equipment. As you suggest, re-evaluation would be required if system changes dictate. 2. The footnote is part of the Applicability Section of the standard. 		
<p>Occidental Chemical Corp. (Ingleside Cogeneration LP)</p>	<p>Yes</p>	<ol style="list-style-type: none"> 1. Ingleside Cogeneration agrees with the distinctions that the project team has made to determine which automatic reclosing components may pose a risk to the BES, and therefore should be subject to PRC-005-3. Clearly those that are incorporated in an SPS have a direct reliability impact. However, it is reasonable to limit applicable to reclosing systems that reside at or near significant generation facilities. 2. We also agree that an exclusion should be allowed wherever the relay owner can demonstrate that the generator protection scheme is configured to withstand a

Organization	Yes or No	Question 1 Comment
		<p>Fault time frame of twice the normal clearing time without severing the Facility from the BES. This is a very conservative risk threshold and properly focuses compliance resources on the most prevalent threats to BES performance.</p> <p>3. Lastly, the limits of the control circuitry functionality testing are also appropriate. The prior version of PRC-005-3 included testing through the breaker trip coils - which may also inadvertently lock out other ancillary functions. Since the only reliability concern is that the reclosing relay will misoperate in a manner that will result in a premature closing signal, it is appropriate that the functional test required by NERC focuses only on that point.</p>
<p>Response: Thank you for your comments and support.</p>		
ReliabilityFirst	Yes	<p>ReliabilityFirst votes in the affirmative because the modifications to this standard further establishes minimum maintenance activities for Automatic Reclosing Component Types and the maximum allowable maintenance intervals. ReliabilityFirst offers the following comments for consideration:</p> <p>1. Table 4-2(a) and 4-2(b) - ReliabilityFirst seeks the technical justification for the maximum maintenance interval of 12 years for unmonitored control circuitry associated with Automatic Reclosing.</p> <p>2. Applicability section 4.2.6.1 - ReliabilityFirst recommends adding the term “nameplate rating” to clarify which generating plants are required have Automatic Reclosing applied. Without this clarifier included, the term “total installed gross generating plant capacity” is subject to interpretation. For example, a plant may have multiple different values for its gross generating plant capacity but a plant will always have one static nameplate rating. The term “nameplate rating” is also consistent with the new NERC BES definition language.</p>
<p>Response: Thank you for your comments.</p> <p>1. PRC-005-3 uses the same interval for ‘Protection System’ Components and the drafting team contends that it is likewise appropriate for ‘automatic reclosing.’</p>		

Organization	Yes or No	Question 1 Comment
<p>2. The drafting team contends the Applicability Section 4.2.6.1 is consistent with the recommendations from the SAMS/SPCS report. See Section 2.4.1 in the Supplementary Reference and FAQ document for more discussion.</p>		
<p>Xcel Energy</p>	<p>Yes</p>	<p>We are supportive of the changes made. But we do have two additional comments:</p> <p>a. The inclusion of Table 4-2(b) in PRC-005-3 raises the concern of where this testing would have been required in PRC-005-2 and raises uncertainty about the drafting team's intentions for the testing requirements for all the various possibilities for actuation of SPS mitigating devices. We were under the impression that row 1 of Table 1-5 in PRC-005-2 required 6 year verification of trip coils or actuators of circuit breakers or other SPS mitigating devices. What if an SPS calls for the closure of a normally open breaker and that close signal is accomplished via some means other than a reclosing relay? Where would the testing of such a breaker closure be required by PRC-005-2 or PRC-005-3? The way PRC-005-3 Table 4-2(b) is phrased it would appear that trip coil operations for circuit breakers in protection systems or SPS's would be required per Table 1-5, row 1 and that close coils that are parts of reclosing schemes are required per tested by Table 4-2(b), row 1, but there does not appear to be testing requirements for any other SPS mitigating devices such turbine runbacks, closure of normally open breakers, disconnect operators, etc. Please clarify testing requirements for SPS mitigating devices outside of breaker trip coils (Table 1-5, row 1) and close coils as utilized in SPS reclosing schemes (Table 4-2(b)) - e.g. turbine throttle valve runback, LTC blocking or enabling, closure of normally open breakers, MOD operation, etc., etc. This appears to be a reliability gap in both PRC-005-2 and PRC-005-3.</p> <p>b. The applicability of reclosing to the Generator Owner & Transmission Owner is dependent upon the GO & TO knowing the characteristics of the Balancing Authority. GOs & TOs do not have this knowledge. There should be an obligation of the BA to inform (and update as needed) the GO and TO of the gross MW value of the largest unit in the BA footprint (or determine the appropriate entity to update the GO & TO). This could be accomplished by adding BA's as an applicable entity to PRC-005-3 and adding a requirement for this notification of TO' s and GO's by the BA to PRC-005-3.</p>

Organization	Yes or No	Question 1 Comment
		Alternatively, the applicable entities for PRC-005-3 could be left as is and the requirement for BA's to notify TO's and GO's could be accomplished by adding a new requirement to a more appropriate standard.
<p>Response: Thank you for your comments.</p> <p>a. PRC-005-3 only deals with control circuits and relays associated with automatic reclosing. All other equipment is already covered in the third row of Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3).</p> <p>b. The addition of a functional entity to the Applicability section of the standard is outside the scope of the SAR for this project. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised.</p>		
Northeast Power Coordinating Council	Yes	
PacifiCorp	Yes	
City of Tallahassee	Yes	
Idaho Power Company	Yes	
City of Tallahassee	Yes	
Oncor Electric Delivery Company LLC	Yes	

2. In response to comments, the drafting team developed an “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area” Do you agree with this additional Implementation Plan? If not, please provide specific suggestions for improvement.

Summary Consideration:

Numerous commenters disagreed with the implementation period specified in the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area” stating that it was too short to accommodate the potential number of newly identified Automatic Reclosing Components that could become applicable nor did it provide enough time for potential outage coordination(s) necessary to perform the required maintenance. Upon reconsideration, the drafting team agreed that the proposed implementation schedule for newly identified Automatic Reclosing Components was inappropriate and could potentially jeopardize reliability by forcing entities to take unscheduled outages to become compliant. The drafting team deemed three years to be sufficient to avoid the reliability concerns and permit entities to implement maintenance in a manner that would be sustainable in the long-term.

In response to comments, the drafting team incorporated the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area” into the full Implementation Plan to consolidate the implementation documents.

In response to a comment, the drafting team inserted the jurisdictional pro-forma language where it had been inadvertently left out of the Implementation Plan. Additionally, NERC will file the errata change with the applicable regulatory authorities as necessary for the PRC-005-2 Implementation Plan.

To avoid confusion, the drafting team modified paragraph 4 of the Background section to remove the references to the implementation timing. The timing is already comprehensively addressed in the implementation plan for each requirement.

Organization	Yes or No	Question 2 Comment
Tri-State Generation and Transmission Association, Inc.	No	"Prior to the end of the following calendar year" is a very ambiguous implementation plan and could require entities to be compliant anywhere between 12 and 24 months. TSGT recommends that the implementation period state 18 months from the first day of the quarter following component identification.

Organization	Yes or No	Question 2 Comment
<p>Response: Thank you for your comments.</p> <p>The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents.</p>		
<p>ACES Standards Collaborators</p>	<p>No</p>	<p>(1) We agree with the need for the additional implementation plan but find it confusing. First, we think that the compliance date should be identified as some interval after the commercial in-service date of the change in generation or the official retirement date. Otherwise, there could be confusion in which year the newly applicable Automatic Reclosing components must be compliant. Consider a new unit begins testing on December 1, 2013 and goes commercial January 31, 2014. One could interpret the language in the implementation plan to require the maintenance activities to be completed by December 31, 2014 or December 31, 2015.</p> <p>(2) To avoid the confusion that occurred with PRC-005-1, the implementation plan should state very clearly that the initial maintenance activities must be performed by the compliance date and that no evidence of prior maintenance activities is required. In essence, the compliance date established in this implementation plan due to changes in generation and the overall implementation plan should be very clear that the compliance date established in these plans is the start of the initial interval. To allow the interval to start before the compliance date would be equivalent to making the standard retroactive.</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents. The Implementation Plan already includes several attributes that address your concern. First, in the Background, the Implementation Plan states, “For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately 		

Organization	Yes or No	Question 2 Comment
<p>compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.” Also in the Background, the Implementation Plan states “Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.” In the General Consideration, the Implementation Plan states, “For activities being added to an entity’s program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.” Finally, in the specific implementation for Requirements R3 and R4 (reflecting the other quoted text), compliance is intended to address the first performance of the respective activities within the associated intervals.</p>		
<p>SERC Protection and Controls Subcommittee</p>	<p>No</p>	<p>1) We prefer that maintenance for newly identified Automatic Reclosing Components be completed within 3 calendar years. This is more consistent with the phased in approach that applies to the overall implementation.</p> <p>2) We prefer a single document with the implementation plan; please combine the 2 documents.</p> <p>The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.</p>
<p>Response: Thank you for your comments.</p> <p>1 and 2) The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents.</p>		
<p>PPL NERC Registered Affiliates</p>	<p>No</p>	<p>1. Regarding the implementation plan for this project, the PPL NERC Registered Affiliates are concerned with the following: “For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4: The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3.” This would require two cycles of 12-year maintenance in five</p>

Organization	Yes or No	Question 2 Comment
		<p>years for 30% of your affected equipment. We recommend that the implementation plan be changed to require that 100% of the affected relays have one maintenance performed by 144 months from the implementation date of the standard.</p> <p>2. The implementation plan states: "For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3." However, If there is no specific 'bookend' required, and the cycle is truly a 12-year cycle, no evidence of testing or maintenance could be required prior to 144 months from the enforcement date of the standard; but the proposed implementation plan requires the work at 36 months, 60 months, and 84 months, which is short of a 12-year cycle.</p>
<p>Response: Thank you for your comments.</p> <p>Your comments appear to refer to the initial Implementation Plan, rather than the "Implementation Plan for Newly Identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area".</p> <ol style="list-style-type: none"> 1. The premise presented in your comment is incorrect. The Implementation Plan establishes expectations for performance of the initial maintenance under the standard. After the initial performance of the maintenance, the entity is expected to perform ongoing maintenance according to the intervals in Table 4. 2. The statement to which you refer is intended to clarify that auditors should not expect evidence of multiple performances of the maintenance until two full intervals have transpired. The majority of industry agrees with the phased-in approach for implementing the maintenance requirements. 		
<p>North American Generator Forum Standards Review Team</p>	<p>No</p>	<ol style="list-style-type: none"> 1. Regarding the implementation plan for this project, the SRT is concerned with the following: "For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4: The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3." This would require two cycles of 12-year maintenance in five years for 30% of your affected equipment. We recommend that the implementation plan be changed to require that 100% of the affected relays have one maintenance performed by 144

Organization	Yes or No	Question 2 Comment
		<p>months from the implementation date of the standard.</p> <p>2. The implementation plan states: "For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3." However, if there is no specific 'bookend' required, and the cycle is truly a 12-year cycle, no evidence of testing or maintenance should be required prior to 144 months from the enforcement date of the standard; but the proposed implementation plan requires the work at 36 months, 60 months, and 84 months, which is obviously short of a 12-year cycle.</p> <p>A Compliance Enforcement Authority could apply this in the following manner: Entity Y has four reclosing relays, all tested and installed on August 1, 2004. The new PRC-005 Standard becomes effective on July 1, 2014. On August 2, 2014 entity Y could be found in violation if one of the four relays has not gone through the new 12-year required cycle. If the language was changed to 100% compliance by 144 months, with all the earlier steps eliminated, it would work. Specific language needs to be in place noting that no evidence shall be required for any testing prior to the enforcement date, and the 12-year clock starts on that day. The following change would need to be made also: "For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until 288 months following the enforcement date of PRC-005-3."</p>

Response: Thank you for your comments.

Your comments appear to refer to the initial Implementation Plan, rather than the "Implementation Plan for Newly Identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area".

1. The premise presented in your comment is incorrect. The Implementation Plan establishes expectations for performance of the initial maintenance under the standard. After the initial performance of the maintenance, the entity is expected to perform ongoing maintenance according to the intervals in Table 4.
2. The statement to which you refer is intended to clarify that auditors should not expect evidence of multiple performances of the maintenance until two full intervals have transpired. The majority of industry agrees with the phased-in approach for

Organization	Yes or No	Question 2 Comment
implementing the maintenance requirements.		
American Electric Power	No	<p>AEP will reserve its comments on the proposed implementation plan until its concerns on scope are eventually addressed.</p> <p>Due to the current volume of standards development activity, AEP is not able to apply the same level of rigor to this request for comment as we would normally. As a result, the comments provided in this response are those we deemed the most significant, and do not necessary reflect all the issues that AEP may, at some time, choose to address.</p>
Response: Thank you for your comment.		
Manitoba Hydro	No	<p>Although Manitoba Hydro will continue to maintain our “negative” vote for this standard based on concerns from the PRC-005-2 version, we do offer the following clarifying comments to the drafting team regarding PRC-005-3:</p> <p>(1) General comment - the words “Automatic Reclosing Components” are both capitalized and de-capitalized throughout the document. For example, within the definition of a Protection System Maintenance Program (PSMP) the words are de-capitalized, but are then capitalized in PRC-005-3 R3. For consistency, Manitoba Hydro suggests selecting one or the other.</p> <p>(2) Definitions of Terms Used in Standard, PSMP - capitalize the word “component” for consistency with the rest of the standard.</p> <p>(3) Background 4, Retirement of Existing Standards, Implementation Plan for Requirements R1, R2 and R5, Implementation Plan for Requirements R3 and R4, Implementation Plan for Requirements R1, R2 and R5 and Implementation Plan for Requirements R3 and R4 - replace “Board of Trustees” with “Board of Trustees” for consistency with other standards.</p>
Response: Thank you for your comments.		

Organization	Yes or No	Question 2 Comment
<p>1. The drafting team cannot capitalize “automatic reclosing” in the definition of Protection System Maintenance Program (PSMP) because PSMP is a NERC Glossary Term.</p> <p>2. The drafting team cannot capitalize “components” in the definition of Protection System Maintenance Program (PSMP) because PSMP is a NERC Glossary Term.</p> <p>3. The drafting team made the suggested change.</p>		
Consumers Energy	No	<p>Consumer’s Energy Ballot member is voting NEGATIVE on Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) PRC-005-3 since the standard does not address how each entity is expected to obtain the required information “the gross capacity of the largest BES generating unit with the Balancing Authority Area” (in section 4.2.6.1) and know when it changes.</p>
<p>Response: Thank you for your comment.</p> <p>The addition of a functional entity to the Applicability section of the standard is outside the scope of the SAR for this project. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised.</p>		
Dominion	No	<p>Given that most of the Maximum Maintenance Intervals appear to be in the 4-6 year range, we believe that implementation for newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area should be extended to allow up to 36 months from BA notification of such change</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents.</p>		
Pepco Holdings Inc & Affiliates	No	<p>In order to verify the reclosing scheme performance on any newly identified busses, resulting from generation capacity increases, it may require scheduling sequential line</p>

Organization	Yes or No	Question 2 Comment
		<p>outages on all BES lines emanating from the bus in order to test breaker auto-reclosing operations. Also, based on system operating conditions, these individual line outages may require coordination with certain generation outages. As such, due to the outage coordination necessary to perform this testing, it may not be possible to complete all testing and maintenance activities on these newly identified facilities by the end of the following calendar year. For this reason, we would suggest the following language (similar to that used in the first bullet of R3/R4 Section 5 of the April 2013 draft of the PRC-005-3 Implementation Plan) be used for the implementation plan for these newly identified Automatic Reclosing Components: “The responsible entities must complete the maintenance activities, described in Table 4, for any newly identified Automatic Reclosing Components, resulting from the addition, or retirement, of generating units; or increases of gross generation capacity of individual generating units or plants within the Balancing Authority area, by the first day of the first calendar quarter thirty-six (36) months following implementation of the capacity change, which resulted in the identification of these new Automatic Reclosing Components (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents.</p>		
<p>Occidental Chemical Corp. (Ingleside Cogeneration LP)</p>	<p>No</p>	<p>Ingleside Cogeneration contends that the one year time-frame given to incorporate all the components of Automatic Reclosers newly identified as applicable to PRC-005-3 due to a generation change in the BA footprint is insufficient. It is appropriate to require the PSMP to be updated with the new components by that date, but not to conduct the first full set of maintenance activities. Our primary concern is that Ingleside, as a Generator Owner, will not receive timely notification that a substantive change has been made. And although we are willing to reach out to our Balancing</p>

Organization	Yes or No	Question 2 Comment
		<p>Authority on a regular basis - or to establish a notification process - this is not a coordination activity that either of us have historically pursued. Furthermore, the recloser relays maintenance is handled during planned outages. At the very least, we would need an additional three years to schedule and execute the Table 4 maintenance activities in a quality manner. Since a single miss to PRC-005-3 would result in a big dollar penalty, we believe that there is some reasonable leeway that should be provided. Four years beyond the date of the generation change is not excessive - particularly since the failure of reclosing relays has not been found as the cause of a major BES event, or even a common issue in less extensive failures.</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents.</p>		
Southern Company	No	<p>Southern Company contends that the two implementation plans associated with the Standard are in conflict. It can be interpreted that all automatic reclosing components will be ‘newly identified’. As such they would be required to be completed by the end of the following calendar year.</p> <p>We believe that the intent was to have the initial applicable Automatic Reclosing Components to have the same phased in completion dates that were brought forward from PRC-005-2.If that was the intent, an potential conflict exists since after the initial phased in schedule up to 12 yrs is set, a change in the unit applicability could occur one year later which could in the case of ‘largest unit’ retirement bring many more locations into scope all of which would be newly indentified and be subject to the one calendar year requirement.</p> <p>Bottom Line is that the Implementation plan needs to be revisited.</p> <p>Related to the comment to #2 above, we do not specifically see a timeline identified to include the following:1) Identification to identify the units and components</p>

Organization	Yes or No	Question 2 Comment
		<p>covered.2) Identification of the components that may be excluded per the Note.3) Modification to the PSMP4) Actual Implementation</p> <p>If the intent is for all this to be covered in R1 and R2, we question this for the following reasons: o Is this enough time for the initial steps noted above, and o This result in multiple dates for compliance with R1 and R2</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents.</p>		
Idaho Power Company	No	<p>The change in generation could bring in significant numbers of additional units to be added to the testing and maintenance procedures. We would prefer a percentage based approach similar to the implementation plan for the other table items in PRC-005-2.</p>
<p>Response: Thank you for your comment.</p> <p>The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents.</p>		
Xcel Energy	No	<p>The implementation plan for the initial implementation of the program allows for a gradual implementation of requirements R3 and R4 for reclosing relay maintenance activities for those relays determined to be in scope such that 30% must be compliant within 36 months of regulatory approval, 60% compliant within 60 months of regulatory approval, and 100% compliant within 84 months of regulatory approval. The additional implementation plan requires 100% compliance within the next following calendar year even in those circumstances where the retirement of the largest unit in the balancing authority would result in an entirely different set of reclosing relays to be in scope. For consistency, it would be far more reasonable for</p>

Organization	Yes or No	Question 2 Comment
		<p>the additional implementation plan to be aligned with the requirements of the original implementation plan for R3 and R4. Specifically, entities should be compliant with R1, R2, and R5 for the newly in scope schemes at the start of the first calendar quarter 12 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area. For requirements R3 and R4, entities shall be 30% compliant within 36 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area, 60% compliant within 60 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area and 100% compliant within 84 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area.</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents.</p>		
MRO NERC Standards Review Forum (NSRF)	No	The implementation plan should be based upon the existing maintenance schedules for the affected BES components.
<p>Response: Thank you for your comments.</p> <p>The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents.</p>		
American Transmission Company, LLC	No	The implementation plan should be based upon the existing maintenance schedules for the affected BES components.

Organization	Yes or No	Question 2 Comment
<p>Response: Thank you for your comments.</p> <p>The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents.</p>		
Liberty Electric Power	No	<p>The program as written requires 30% compliance at 60 months. This implies two instances of 12-year maintenance have to occur in 5 years, or 19 years earlier than should be required. The plan should be changed to all relays must have the first maintenance completed by 144 months from the effective date of the standard.</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents.</p>		
Independent Electricity System Operator	No	<p>We appreciate the drafting team’s effort to insert appropriate wording to remove a potential conflict with Ontario regulatory practice with respect to the effective date of the standard. However, there are still a couple of places where this insertion is missing. Please insert: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” prior to the wording “,or in those jurisdiction....” in Section 4 on P.2 and in the first paragraph under the Retirement of Existing Standards” on P.3.</p>
<p>Response: Thank you for your comments.</p> <p>The drafting team modified the Implementation Plan to incorporate the intent of your suggestion.</p>		
Cleco	No	<p>We do not believe reclosing relays are protective devices and therefore are not subject to this level of oversight. Second, the strongest justification was that if the relay failed to operate correctly and reclosed instantaneously, the generator would be</p>

Organization	Yes or No	Question 2 Comment
		subject to additional fault duty. We have not seen such a failure and do not see the justification for including reclosing relays or restoration devices in a Protection System Maintenance & Testing Standard. Major storm events near the station or breakers failing to latch are far more likely to cause sequential faults.
<p>Response: Thank you for your comments.</p> <p>FERC Order 758 directed that maintenance of reclosing relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive, and follows the recommendations included in the SAMS/SPCS technical document “Considerations for Maintenance and Testing of Autoreclosing Schemes.”</p>		
Duke Energy	Yes	<ol style="list-style-type: none"> 1. Duke Energy requests clarification from the drafting team as to whom they envision identifying the newly acquired Automatic Reclosing Components, how they must identify, and what documentation is needed to show correspondence with an entity’s maintenance program. 2. Also, Duke Energy suggests that the drafting team consider placing the Implementation Plan for Newly identified Automatic Reclosing Components in the standard itself, and not as its own document.
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. The applicable entity is expected to communicate with its BA(s) to identify applicable Automatic Reclosing components (in accordance with the Applicability). How the correspondence is documented is left to the discretion of the entity. 2. The drafting team added additional time to the “Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area.” The document was also incorporated into the full Implementation Plan to consolidate the implementation documents. 		
Northeast Power Coordinating Council	Yes	<ol style="list-style-type: none"> 1. Referencing Applicability Section 4.2.6, the Balancing Authority has to notify and provide documentation to the appropriate entities in 4.2.6.1 and 4.2.6.2 that automatic reclosing maintenance is required. TO substations within 10 circuit miles will need to be identified by the Balancing Authority as well. 2. To clarify Footnote 1 on page 4, suggest the following rewording:Automatic

Organization	Yes or No	Question 2 Comment
		<p>Reclosing as addressed in Sections 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 not cleared for the length of a breaker trip-close-trip operating time does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.</p> <p>3. In the Implementation Plan the drafting team did a good job inserting the appropriate wording to remove a potential conflict with regulatory practice with respect to the effective date of the standard. However, the wording needs to be inserted in Section 4 of the Background Section. Review the Implementation Plan and insert the following words where appropriate:”, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” The Implementation Plan must be made available throughout the life of the Standard.</p>
<p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> 1. The addition of a functional entity to the Applicability section of the standard is outside the scope of the SAR for this project. The drafting team understands the request but contends that such a requirement would be more appropriately included in a Reliability Standard applicable to Balancing Authorities; consequently, the drafting team has added this issue to the NERC Issues Database for consideration when the pertinent Reliability Standard is revised. The drafting team contends that the Transmission Owner, Generator Owner, and Distribution Provider are responsible to identify topology issues such as those to which you refer. 2. The drafting team contends the footnote is consistent with the recommendations from the SAMS/SPCS report. 3. The drafting team updated the Implementation Plan language. 		
Oklahoma Gas & Electric	Yes	
SPP Standards Review Group	Yes	
Western Area Power	Yes	

Organization	Yes or No	Question 2 Comment
Administration		
PacifiCorp	Yes	
Tacoma Power	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Texas Reliability Entity, Inc.	Yes	
Oncor Electric Delivery Company LLC	Yes	
ITC	Yes	

END OF REPORT

Standard Development Roadmap

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

Development Steps Completed:

1. Standards Committee approved posting SAR and draft standard on January 17, 2013.
2. SAR posted for 30-day informal comment period from April 5, 2013 through May 6, 2013.
3. Draft 1 of PRC-005-3 posted for a 30-day formal comment period from April 5, 2013 through May 6, 2013.
4. Draft 2 of PRC-005-3 posted for a 45-day formal comment period from July 10, 2013 through August 23, 2013.
5. Draft 2 of PRC-005-3 passed ballot with Quorum – 78.33% and Approval – 79.24%.

Description of Current Draft:

This is the second draft of the PRC-005-3. The standard modifies PRC-005-2 to address the directive issued by the Federal Energy Regulatory Commission in Order No.758 for “NERC to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System...”

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct final ballot	October 2013
2. BOT Adoption	November 2013

Definitions of Terms Used in Standard

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

Protection System Maintenance Program (PSMP) (NERC Board of Trustees Approved Definition)

— An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

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

Automatic Reclosing –

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

A. Introduction

- 1. Title:** **Protection System and Automatic Reclosing Maintenance**
- 2. Number:** PRC-005-3
- 3. Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
- 4. Applicability:**
 - 4.1. Functional Entities:**
 - 4.1.1** Transmission Owner
 - 4.1.2** Generator Owner
 - 4.1.3** Distribution Provider
 - 4.2. Facilities:**
 - 4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4** Protection Systems installed as a Special Protection System (SPS) for BES reliability.
 - 4.2.5** Protection Systems for 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 for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
 - 4.2.6** Automatic Reclosing¹, including:
 - 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

¹ Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

- 4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.
- 4.2.6.3 Automatic Reclosing applied as an integral part of an SPS specified in Section 4.2.4.

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

B. Requirements

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

The PSMP shall:

- 1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2. Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

- R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

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.

C. Measures

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

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

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

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

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification

Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.3. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

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

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p>

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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: <ul style="list-style-type: none"> • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific

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

E. Regional Variances

None

F. Supplemental Reference Document

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

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 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

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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 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
3	TBD	Revised to include Automatic Reclosing in maintenance programs	Project 2007-17.2 Revision to address the FERC directive in Order No.758 regarding Automatic Reclosing

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

² For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). 	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

<p align="center">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)</p> <p align="center">Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

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

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

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

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	<p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate. <p>For microprocessor relays:</p> <ul style="list-style-type: none"> • 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.
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> • 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. <p>Alarming for power supply failure (See Table 2).</p>	12 Calendar Years	<p>Verify:</p> <ul style="list-style-type: none"> • 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
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • 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). <p>Alarming for change of settings (See Table 2).</p>	12 Calendar Years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). 	12 Calendar Years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an SPS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

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

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

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

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

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

***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.*

***Countable Event** – A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action, or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.*

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

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4%

of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Standard Development Roadmap

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

Development Steps Completed:

1. Standards Committee approved posting SAR and draft standard on January 17, 2013.
2. SAR posted for 30-day informal comment period from April 5, 2013 through May 6, 2013.
3. Draft 1 of PRC-005-3 posted for a 30-day formal comment period from April 5, 2013 through May 6, 2013.
4. Draft 2 of PRC-005-3 posted for a 45-day formal comment period from July 10, 2013 through August 23, 2013.
5. Draft 2 of PRC-005-3 passed ballot with Quorum – 78.33% and Approval – 79.24%.

Description of Current Draft:

This is the second draft of the PRC-005-3. The standard modifies PRC-005-2 to address the directive issued by the Federal Energy Regulatory Commission in Order No.758 for “NERC to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System...”

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for a concurrent 45-day comment and ballot	July 2013
2.1. Conduct recirculation <u>final</u> ballot	October 2013
3.2. BOT Adoption	November 2013

Definitions of Terms Used in Standard

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

Protection System Maintenance Program (PSMP) (NERC Board of Trustees Approved Definition)

— An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

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

Automatic Reclosing –

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

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Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

A. Introduction

- 1. Title:** Protection System and Automatic Reclosing Maintenance
- 2. Number:** PRC-005-3
- 3. Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
- 4. Applicability:**
 - 4.1. Functional Entities:**
 - 4.1.1** Transmission Owner
 - 4.1.2** Generator Owner
 - 4.1.3** Distribution Provider
 - 4.2. Facilities:**
 - 4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4** Protection Systems installed as a Special Protection System (SPS) for BES reliability.
 - 4.2.5** Protection Systems for 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 for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
 - 4.2.6** Automatic Reclosing¹, including:
 - 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

¹ Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

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

5. Effective Date: See Implementation Plan

B. Requirements

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

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

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.

C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.
- For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)
- For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification

Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.3. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

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

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p>

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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: <ul style="list-style-type: none"> • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific

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

E. Regional Variances

None

F. Supplemental Reference Document

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

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 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

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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 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
3	TBD	Revised to include Automatic Reclosing in maintenance programs	Project 2007-17.2 Revision to address the FERC directive in Order No.758 regarding Automatic Reclosing

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

² For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). 	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • 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

<p style="text-align: center;">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)</p> <p style="text-align: center;">Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

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

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

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

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	<p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate. <p>For microprocessor relays:</p> <ul style="list-style-type: none"> • 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.
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> • 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. <p>Alarming for power supply failure (See Table 2).</p>	12 Calendar Years	<p>Verify:</p> <ul style="list-style-type: none"> • 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
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • 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). <p>Alarming for change of settings (See Table 2).</p>	12 Calendar Years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Internal self diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). 	12 Calendar Years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an SPS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

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

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

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

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

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

***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.*

***Countable Event** – A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action, or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.*

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

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4%

of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Standard Development Roadmap

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

Development Steps Completed:

1. Standards Committee approved posting SAR and draft standard on January 17, 2013.
2. SAR posted for 30-day informal comment period from April 5, 2013 through May 6, 2013.
3. Draft 1 of PRC-005-3 posted for a 30-day formal comment period from April 5, 2013 through May 6, 2013.
4. Draft 2 of PRC-005-3 posted for a 45-day formal comment period from July 10, 2013 through August 23, 2013.
5. Draft 2 of PRC-005-3 passed ballot with Quorum – 78.33% and Approval – 79.24%.

Description of Current Draft:

This is the second draft of the PRC-005-3. The standard modifies PRC-005-2 to address the directive issued by the Federal Energy Regulatory Commission in Order No.758 for “NERC to include the maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System...”

Future Development Plan:

<u>Anticipated Actions</u>	<u>Anticipated Date</u>
<u>1. Conduct final ballot</u>	<u>October 2013</u>
<u>2. BOT Adoption</u>	<u>November 2013</u>

Definitions of Terms Used in Standard

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

Protection System Maintenance Program (PSMP) (NERC Board of Trustees Approved Definition) — An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

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

Automatic Reclosing –

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

A. Introduction

1. **Title:** Protection System and Automatic Reclosing Maintenance
2. **Number:** PRC-005-~~23~~
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that ~~these Protection Systemsthey~~ are kept in working order.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Transmission Owner
 - 4.1.2 Generator Owner
 - 4.1.3 Distribution Provider
 - 4.2. **Facilities:**
 - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4 Protection Systems installed as a Special Protection System (SPS) for BES reliability.
 - 4.2.5 Protection Systems for 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 for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
 - 4.2.6 Automatic Reclosing¹, including:
 - 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

¹ Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

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

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

B. Requirements

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

Component Type—Any one of the five specific elements of the Protection System definition.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

The PSMP shall:

- 1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2. Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2,

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

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

Table 3, and Table 34-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.

- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 34-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

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.

C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.
- For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)
- For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each ~~protection~~Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and ~~Table 34-1 through 4-2~~. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

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

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.3. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

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

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p><u>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</u></p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3, <u>and Tables 4-1 through 4-2</u> where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity <u>entity’s</u> PSMP failed to specify whether three <u>four</u> or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p>

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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: <ul style="list-style-type: none"> • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the segmentSegment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3, <u>and Tables 4-1 through 4-2.</u>	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3, <u>and Tables 4-1 through 4-2.</u>	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3, <u>and Tables 4-1 through 4-2.</u>	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3, <u>and Tables 4-1 through 4-2.</u>
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain

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

E. Regional Variances

None

F. Supplemental Reference Document

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

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 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

Standard PRC-005-2-3 — Protection System and Automatic Reclosing Maintenance

1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	<u>Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0</u>
<u>3</u>	<u>TBD</u>	<u>Revised to include Automatic Reclosing in maintenance programs</u>	<u>Project 2007-17.2 Revision to address the FERC directive in Order No.758 regarding Automatic Reclosing</u>

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years Calendar <u>Years</u>	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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 Calendar <u>Years</u>	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values. •

² For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1
Component Type - Protective Relay
Excluding distributed UFLS and distributed UVLS (see Table 3)

Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • 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). 	<p>12 calendar years <u>Calendar</u> <u>Years</u></p>	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

**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 <u>Calendar Months</u>	Verify that the communications system is functional.
	6 calendar years <u>Calendar Years</u>	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 <u>Calendar Years</u>	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: <ul style="list-style-type: none"> • 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 <u>Calendar Years</u>	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 <u>Calendar Years</u>	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a)
Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	-Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

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

Table 1-4(f)		
Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 calendar years <u>Calendar Years</u>	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 <u>Calendar Years</u>	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS. <u>(See Table 4-2(b) for SPS which include Automatic Reclosing.)</u>	12 calendar years <u>Calendar Years</u>	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 calendar years <u>Calendar Years</u>	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPS <u>SPSs</u> whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring

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

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

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 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate. For microprocessor relays: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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 Calendar Years	Verify: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 calendar years <u>Calendar</u> <u>Years</u>	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 <u>Calendar</u> <u>Years</u>	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 <u>Calendar</u> <u>Years</u>	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 <u>Calendar</u> <u>Years</u>	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		
<u>Component Attributes</u>	<u>Maximum Maintenance Interval</u>	<u>Maintenance Activities</u>
<p><u>Any unmonitored reclosing relay not having all the monitoring attributes of a category below.</u></p>	<p><u>6 Calendar Years</u></p>	<p><u>Verify that settings are as specified.</u></p> <p><u>For non-microprocessor relays:</u></p> <ul style="list-style-type: none"> • <u>Test and, if necessary calibrate</u> <p><u>For microprocessor relays:</u></p> <ul style="list-style-type: none"> • <u>Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</u>
<p><u>Monitored microprocessor reclosing relay with the following:</u></p> <ul style="list-style-type: none"> • <u>Internal self diagnosis and alarming (See Table 2).</u> • <u>Alarming for power supply failure (See Table 2).</u> 	<p><u>12 Calendar Years</u></p>	<p><u>Verify:</u></p> <ul style="list-style-type: none"> • <u>Settings are as specified.</u> • <u>Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</u>

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
<u>Component Attributes</u>	<u>Maximum Maintenance Interval</u>	<u>Maintenance Activities</u>
<u>Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.</u>	<u>12 Calendar Years</u>	<u>Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.</u>
<u>Control circuitry associated with Automatic Reclosing that is not part of an SPS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)</u>	<u>No periodic maintenance specified</u>	<u>None.</u>

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

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

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

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

1. Develop a list with a description of Components included in each designated Segment ~~of the Protection System Component population~~, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 ~~and~~ Table 3, ~~and Tables 4-1 through 4-2~~ until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

***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.*

***Countable Event**—A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.*

***Countable Event** – A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action, or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.*

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

1. At least annually, update the list of ~~Protection System~~ Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.

3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a ~~Protection System~~ Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Implementation Plan Protection System and Automatic Reclosing Maintenance PRC-005-3

Standards Involved

Approval:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Retirements:

- PRC-005-2 – Protection System Maintenance
- PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 – Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program
- PRC-011-0 – Undervoltage Load Shedding System Maintenance and Testing
- PRC-017-0 – Special Protection System Maintenance and Testing

Prerequisite Approvals:

N/A

Background:

Reliability Standard PRC-005-2 with its associated Implementation Plan was approved by the NERC Board of Trustees in November 2012 and has been filed with the applicable regulatory authorities for approval. The Implementation Plan for PRC-005-3 addresses both Protection Systems as outlined in PRC-005-2 and Automatic Reclosing components. PRC-005-3 establishes minimum maintenance activities for Automatic Reclosing Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-3 requires entities to revise the Protection System Maintenance Program by now including Automatic Reclosing Components. The implementation plan established under PRC-005-2 remains unchanged except for the addition of Automatic Reclosing Components required under PRC-005-3.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry-forward requirements from PRC-005-2, establish minimum maintenance activities for Protection System and Automatic Reclosing Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.

2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.
3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth below in this document carries forward the implementation schedules contained in PRC-005-2 and includes changes needed to address the addition of Automatic Reclosing Components in PRC-005-3.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standard PRC-005-3, in accordance with this implementation plan.

While entities are transitioning to the requirements of PRC-005-2, or the combined successor standard PRC-005-3, each entity must be prepared to identify:

- All of its applicable Protection System and Automatic Reclosing Components.
- Whether each component has last been maintained according to PRC-005-2 (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof.

For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active throughout the phased implementation period of PRC-005-3 and shall be applicable to an entity's Protection System Component maintenance activities not yet transitioned to PRC-005-3. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2.

The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees' adoption.

Implementation Plan for Definition:

Protection System Maintenance Program – Entities shall use this definition when implementing any portions of R1, R2 R3, R4 and R5 which use this defined term.

Implementation Plan for Requirements R1, R2 and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
6. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or

as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
7. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3 or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area:

This applies to PRC-005-3 and successor standards.

Additional applicable Automatic Reclosing Components may be identified because of the addition or retirement of generating units; or increases of gross generation capacity of individual generating units or plants within the Balancing Authority Area.

In such cases, the responsible entities must complete the maintenance activities, described in Table 4, for the newly identified Automatic Reclosing Components prior to the end of the third calendar year following the identification of those Components unless documented prior maintenance fulfilling the requirements of Table 4 is available.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Implementation Plan Protection System and Automatic Reclosing Maintenance PRC-005-3

Standards Involved

Approval:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Retirements:

- PRC-005-2 – Protection System Maintenance
- PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 – Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program
- PRC-011-0 – Undervoltage Load Shedding System Maintenance and Testing
- PRC-017-0 – Special Protection System Maintenance and Testing

Prerequisite Approvals:

N/A

Background:

Reliability Standard PRC-005-2 with its associated Implementation Plan was approved by the NERC Board of Trustees in November 2012 and has been filed with the applicable regulatory authorities for approval. The Implementation Plan for PRC-005-3 addresses both Protection Systems as outlined in PRC-005-2 and Automatic Reclosing components. PRC-005-3 establishes minimum maintenance activities for Automatic Reclosing Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-3 requires entities to revise the Protection System Maintenance Program by now including Automatic Reclosing Components. The implementation plan established under PRC-005-2 remains unchanged except for the addition of Automatic Reclosing Components required under PRC-005-3.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry-forward requirements from PRC-005-2, establish minimum maintenance activities for Protection System and Automatic Reclosing Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.

2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.
3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth [below](#) in this document carries forward the implementation schedules contained in PRC-005-2 and includes changes needed to address the addition of Automatic Reclosing Components in PRC-005-3. ~~According to the combined implementation plan in this document, entities must develop their revised Protection System Maintenance Program within twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty four (24) months following NERC Board of Trustees adoption of PRC-005-2. This anticipates that it will take approximately twelve (12) months to achieve regulatory approvals following the November 2012 adoption of PRC-005-2 by the NERC Board of Trustees.~~
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standard PRC-005-3, in accordance with this implementation plan.

While entities are transitioning to the requirements of PRC-005-2, or the combined successor standard PRC-005-3, each entity must be prepared to identify:

- All of its applicable Protection System and Automatic Reclosing Components.
- Whether each component has last been maintained according to PRC-005-2 (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof.

For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active throughout the phased implementation period of PRC-005-3 and shall be applicable to an entity's Protection System Component maintenance activities not yet transitioned to PRC-005-3. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2, [or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities](#); or, in those jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2.

The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of [the](#) first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees' adoption.

Implementation Plan for Definition:

Protection System Maintenance Program – Entities shall use this definition when implementing any portions of R1, R2 R3, R4 and R5 which use this defined term.

Implementation Plan for Requirements R1, R2 and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:
 - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:
 - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage), or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
6. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or

as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
7. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4:
- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
 - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area:

This applies to PRC-005-3 and successor standards.

Additional applicable Automatic Reclosing Components may be identified because of the addition or retirement of generating units; or increases of gross generation capacity of individual generating units or plants within the Balancing Authority Area.

In such cases, the responsible entities must complete the maintenance activities, described in Table 4, for the newly identified Automatic Reclosing Components prior to the end of the third calendar year following the identification of those Components unless documented prior maintenance fulfilling the requirements of Table 4 is available.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Supplementary Reference and FAQ

PRC-005-3 Protection System Maintenance

October 2013

RELIABILITY | ACCOUNTABILITY



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1. Introduction and Summary

Note: This supplementary reference for PRC-005-3 is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive, and, when approved, will supersede PRC-005-2.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-3 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the [NERC Glossary of Terms](#) used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- 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.

2.3 Applicability of New Protection System Maintenance Standards

The BES purpose is to transfer bulk power. The applicability language has been changed from the original PRC-005:

“...affecting the reliability of the Bulk Electric System (BES)...”

To the present language:

“...that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).”

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution

Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

NERC's approved definition of Bulk Electric System is:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.

The BES definition is presently undergoing the process of revision.

Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a [June 14, 2007 Informational Filing](#).

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your “non-BES circuit breaker” has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the “Facilities” section of “Applicability” track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Special Protection Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 94 (tripping or trip-free relay), as these devices are tripping relays that respond to the trip signal of the protective relay that processed the signals from the current and voltage-sensing devices.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.6.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

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.

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 a SPS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that

a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES unit within the Balancing Authority Area where the Automatic Reclosing is applied.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

How do I interpret Applicability Section 4.2.6 to determine applicability in the following examples:

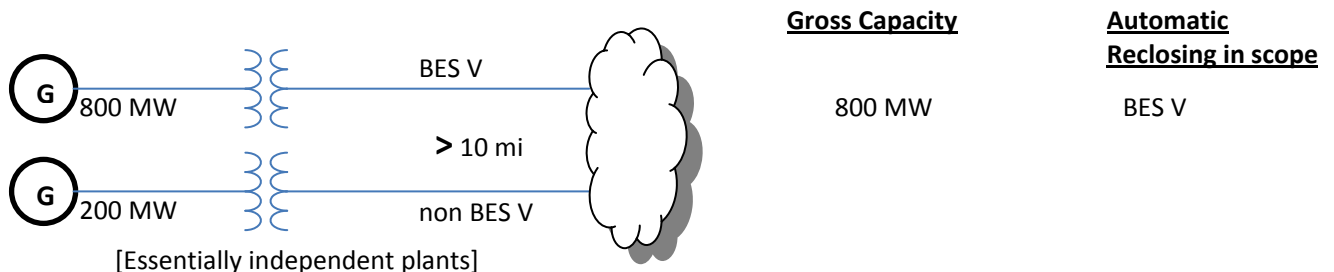
At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.

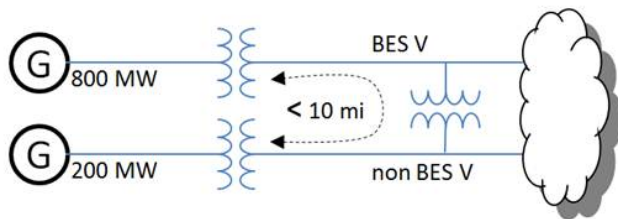


Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



Gross Capacity

1000 MW

Automatic Reclosing in scope

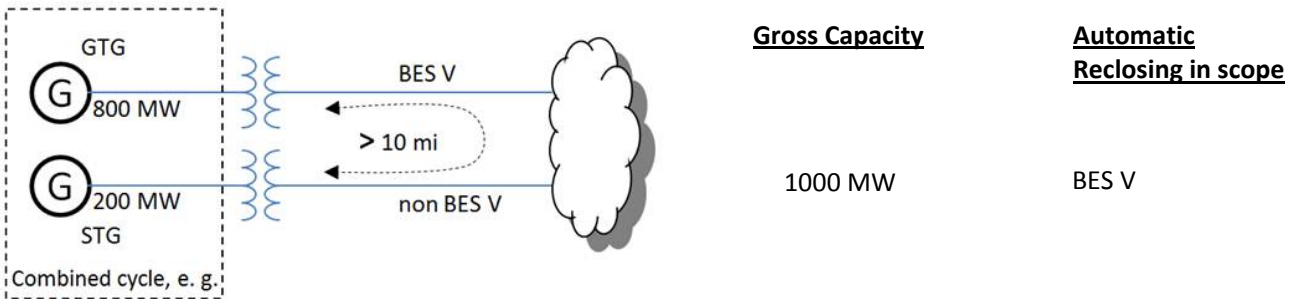
BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.

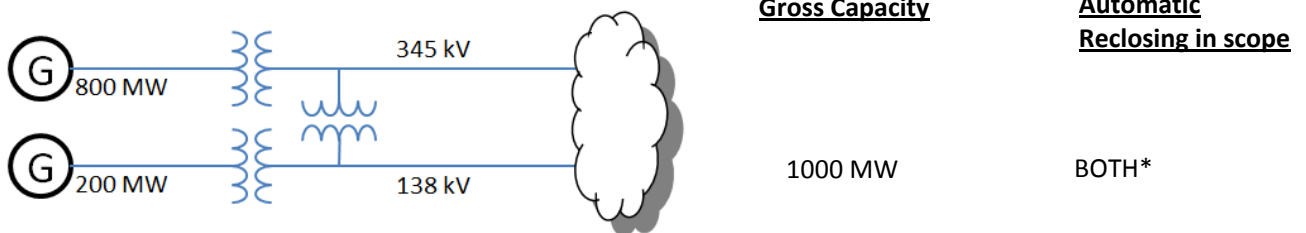


Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.6.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.6.1.



* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.6.2 specify “10 circuit miles”?

As noted in “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.6.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be “one bus away” from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. “One bus away” is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of “Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)”?

Reverse power relays are often installed to detect situations where the transmission source becomes deenergized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not ‘installed for the purpose of detecting’ these faults.

Is a Sudden Pressure Relay an auxiliary tripping relay?

No. IEEE C37.2-2008 assigns the Device No. 94 to auxiliary tripping relays. Sudden pressure relays are assigned Device No. 63. Sudden pressure relays are presently excluded from the standard because it does not utilize voltage and/or current measurements to determine anomalies. Devices that use anything other than electrical detection means are excluded. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent

with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

My mechanical device does not operate electrically and does not have calibration settings; what maintenance activities apply?

You must conduct a test(s) to verify the integrity of any trip circuit that is a part of a Protection System. This standard does not cover circuit breaker maintenance or transformer maintenance. The standard also does not presently cover testing of devices, such as sudden pressure relays (63), temperature relays (49), and other relays which respond to mechanical parameters, rather than electrical parameters. There is an expectation that Fault pressure relays and other non-electrically initiated devices may become part of some maintenance standard. This standard presently covers trip paths. It might seem incongruous to test a trip path without a present requirement to test the device; and, thus, be arguably more work for nothing. But one simple test to verify the integrity of such a trip path could be (but is not limited to) a voltage presence test, as a dc voltage monitor might do if it were installed monitoring that same circuit.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: “A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.”

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: “A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.”

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-

based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft 86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing –

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay .

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action or a Protection System Misoperation attributed to hardware

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

4.1 Frequently Asked Questions:

Why does PRC-005-3 not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-3 requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the “Tables”), and the various components of the definition established for a “Protection System Maintenance Program,” PRC-005-3 establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by “restore” in the definition of maintenance.

The description of “restore” in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity “shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.” Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by “...demonstrate efforts to correct an Unresolved Maintenance Issue...”; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and

management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase “demonstrate efforts to correct” (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a “closed-end process”). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System and Automatic Reclosing Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System and Automatic Reclosing Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers’ recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.
- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term “Condition-Based-Maintenance” (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the “monitored-basis-time-intervals” existing within the standard, the

explanatory discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

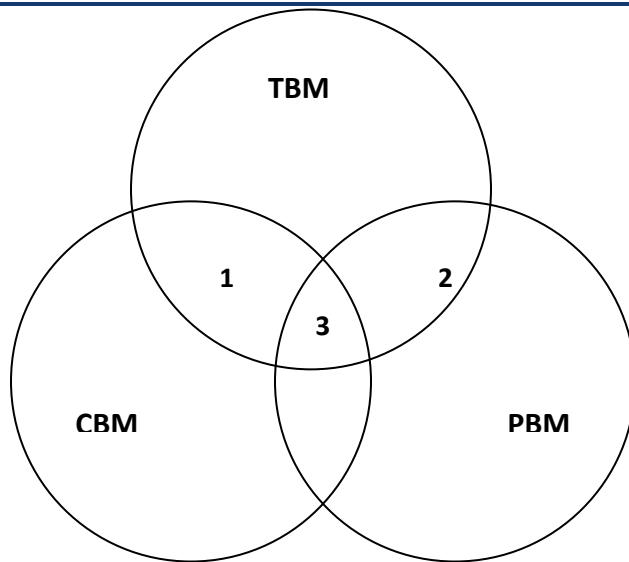
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to **ONLY** perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a “flow chart” of the standard.

We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

-
- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
 - Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

Excessive maintenance can actually decrease the reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.4) of the standard, is it necessary to

provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

“All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center.”

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

“Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability.”

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a combination of time-based and condition-based maintenance. The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-3. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-3.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a "One Calendar Year Interval," the next event would have to occur on or before December 31, 2010.

Please provide an example of "4 Calendar Months".

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May)

would still be due four months later therefore the activity is due again July. Basically every “four Calendar Months” means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions' section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

-
- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- 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 as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

-
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
 - Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Special Protection System. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, and Table 4 in the standard specify maximum allowable verification intervals for various generations of Protection Systems and Automatic Reclosing and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in [Figures 1](#) and [2](#) at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. [Figure 2](#) shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and SPS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-3:

-
- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
 - Table 1-1 is for protective relays,
 - Table 1-2 is for the associated communications systems,
 - Table 1-3 is for current and voltage sensing devices,
 - Table 1-4 is for station dc supply and
 - Table 1-5 is for control circuits.
 - Table 2, is for alarms; this was broken out to simplify the other tables.
 - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
 - Table 4 is for Automatic Reclosing.
 - Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
 - This Maintenance activity is the minimum maintenance activity that must be documented.
 - If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
 - After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
 - If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
 - Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
 - An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows

maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-3. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-3, most notable of which is an entity using performance based maintenance methodology. If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc, are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.
2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.
3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or SPS (as opposed to a monitoring task) must be verified as a component in a Protection System.
4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-3 for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-3 is a more economical approach while addressing the reliability requirements of the BES.
5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform

properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).
7. “End-to-end test,” as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.
8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.
9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by “Verify that settings are as specified” maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states “...settings are as specified.”

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require “...that the relay settings be correct...” because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have “drifted” since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the “Verify that settings are as specified” maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about SPS interfaces between different entities or owners?

As in all of the Protection System requirements, SPS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Special Protection System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the SPS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for SPS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an SPS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an SPS scheme should that occur. Forced trip tests of circuit breakers (etc) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unnecessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval, then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays

-
- Neutral overcurrent relay
 - Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A

distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-3 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or to the previous scheduled (on-site) audit date, whichever is longer.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please use a specific example to demonstrate the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld. For example: “Company A” has a maintenance plan that requires its electromechanical protective relays be tested every three calendar years, with a maximum allowed grace period of an additional 18 months. This entity would be required to maintain its records of maintenance of its last two routine scheduled tests. Thus, its test records would have a latest routine test, as well as its previous routine test. The interval between tests is, therefore, provable to an auditor as being within “Company A’s” stated maximum time interval of 4.5 years.

The intent is not to require three test results proving two time intervals, but rather have two test results proving the last interval. The drafting team contends that this minimizes storage requirements, while still having minimum data available to demonstrate compliance with time intervals.

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-3, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-3 assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-3 requires performance of maintenance activities that are deemed necessary to detect and correct plausible age and service related degradation of components, such that a properly built and commission tested Protection System will continue to function as designed over its service life.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-3 would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the “Calendar Year” language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a “grace period” without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original Protection System Maintenance – A Technical Reference in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for “time-interval extensions” or “grace periods” to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. “Maximum time intervals” by their very term negates any “time-interval extension” or “grace periods.” To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was “...no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years...” The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table’s use of the term “Calendar” in the column for “Maximum Maintenance Interval.” The PSMT SDT deemed it necessary to include the term “Calendar” to

facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term “Calendar” to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity’s use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as *ISO 9001-2000, Quality Management Systems – Requirements*; or applicable parts of the NIST Baldrige National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is “the sampling distribution of the sample mean can be approximated by a normal probability distribution.” The Central Limit Theorem states: “In selecting simple random samples of size n from a population, the sampling distribution of the sample mean \bar{x} can be approximated by a normal probability distribution as the sample size becomes large.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

“... whenever we are using a large simple random sample (rule of thumb: $n \geq 30$), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

“If samples of size n , when $n \geq 30$, are drawn from any population with a mean μ and a standard deviation σ , the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation.” (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)

“The sample size is large (generally $n \geq 30$)... (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)

“... the normal is often used as an approximation to the t distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection.” (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a “Pass/Fail” format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z \sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1 - \pi) \left(\frac{z}{B} \right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.96 \text{ (This equates to a 95\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=59.0$.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

$$B = 5\%$$

$$z = 1.44 \text{ (85\% confidence level)}$$

$$\pi = 4\%$$

Using the equation above, $n=31.8$.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

Performance-Based Program Evaluation Example

The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.

In consideration of the use of Performance Based Maintenance (PBM), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval (in years) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment (units per year), or any misoperation attributable to hardware failure or calibration failure found within the entire segment (1000 units) during the testing year.

Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: $125 \times .04 = 5$. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations (attributable to hardware or calibration failure within the testing year) associated with the entire segment of 1000 units.

Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: $63 \times .04 = 2.5$.

As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.

Total number of units in the segment	1000
Failure rate	4.00%

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

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.

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.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

9.2 Frequently Asked Questions:

I’m a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect

to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure rate (zero failures) while Type "Y" would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment performance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, “reset the clock” on everything you’ve done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that “resetting the clock” should not be construed as interfering with an entity’s routine testing schedule because the “clock-reset” would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is

allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that “replaced relay” will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. $6/200 = 3\%$ failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. $6/100 = 6\%$ failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year ($1000/8$). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. $6/125 = 5\%$ failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year ($1000/7$). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. $6/143 = 4.2\%$ failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year ($1000/6$). After a year, they again find six failures out of the 167 units tested. $6/167 = 3.6\%$ failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures “Control Circuitry” as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity’s specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device

that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year ($1000/12$). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures “voltage and current inputs to the protective relays” as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a “Relay Scheme.” Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT’s or specific PT’s. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 2000 “Relay Schemes,” all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT’s. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity’s relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their “Voltage and Current Sensing” population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays “that are designed to provide protection for the BES,” this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its

regularly scheduled cycle. (However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays “out-of-service”. What are our responsibilities when it comes to “out-of-service” devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-3 are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-3. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-3 to remove such component(s). Obviously, prudence would dictate that an “out-of-service” device is truly made inactive. There are no record requirements listed in PRC-005-3 for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-3 requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-3 requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

“R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.”

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state “...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues...” The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-3 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

These relays are defined as the devices that receive the input signal from the current and voltage sensing devices and are used to isolate a Faulted Element of the BES. Devices that sense thermal, vibration, seismic, pressure, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
 - There is no specific protective relay commissioning test or relay routine test mandated.
 - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the

protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and vars around the entire bus; this should add up to zero watts and zero vars, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "...verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ..." Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay

and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor-based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately “verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ...” while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "...designed to provide protection for the BES..." then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

While relays that do not respond to electrical quantities are presently excluded from this standard, their control circuits are included if the relay is installed to detect Faults on BES Elements. Thus, the control circuit of a BES transformer sudden pressure relay should be verified every 12 years, assuming its integrity is not monitored. While a sudden pressure relay control circuit is included within the scope of PRC-005-2, other alarming relay control circuits, (i.e., SF-6 low gas) are not included, even though they may trip the breaker being monitored.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes

that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-3 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-3 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-3 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.

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- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-3 applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have an non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- 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.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, “station batteries” are replaced with “station dc supply” to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-3 is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by “continuity” of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.

- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the

station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example “Conductance Readings” from one manufacturer’s test equipment do not correlate to “Impedance Readings” from a different manufacturer’s test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity

readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries).

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery

containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance “as designed” vs. battery performance “as manufactured.” The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer’s rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trendline against the established baseline. The type of probe and its location (post, connector, etc) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measurable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be “forming” after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an "adequate" ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one

minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-3 is there a maintenance activity to inspect the structural integrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.

Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the “Unintentional dc Grounds” requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a “check-off” of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to “all cells,” is it sufficient to have a documentation method that refers to “all cells,” or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-3 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980’s several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery’s current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The

inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "...depending on the degree of change a performance test, cell replacement or other corrective action may be necessary..." (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or

above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid 1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically

trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to “measure battery cell/unit internal ohmic values.” Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is “...verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline.” This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to “Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.”

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to ‘perform as manufactured.’ It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the “perform as manufactured six-month test” at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the “thermal runaway test” at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float

(charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to “verify station dc supply voltage” every “4 calendar months” (see table 1-4(a)), the owner can install a monitoring and alarming device “with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure” and “no periodic verification of station dc supply voltage is required” (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install “electrolyte level monitoring and alarming in every cell” and “unintentional dc ground monitoring and alarming” (see second and third rows of table 1-4(f)), the owner will have to “inspect electrolyte level and for unintentional grounds” every “4 calendar months” (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to “Protection System Control Circuitry”, rather than those portions of the table applicable to communications equipment.

What is meant by “Channel” and “Communications Systems” in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the “channel” as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting “performance criteria.” What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These

limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe “form-b” contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "...does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature autoreclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage

supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that is not part of an SPS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that is part of an SPS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the SPS, and must be verified.

15.9 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.9.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics

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- Maintenance records
 - Logs (operator, substation, and other types of log)
 - Inspection forms
 - Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
 - Check-off forms (paper or electronic)
 - Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 (“Special Protection System Misoperation”). Can I also use it to show compliance for this Standard, PRC-005-3?

Maintaining evidence for operation of Special Protection Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-3.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

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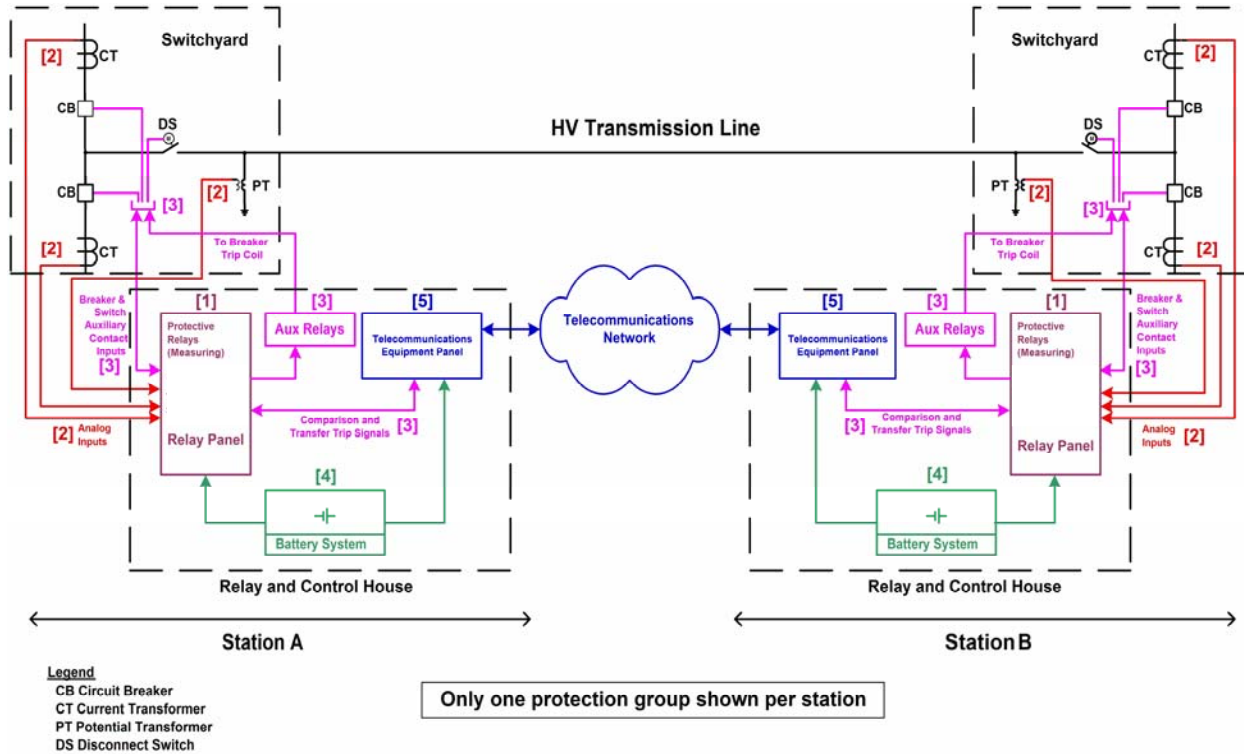
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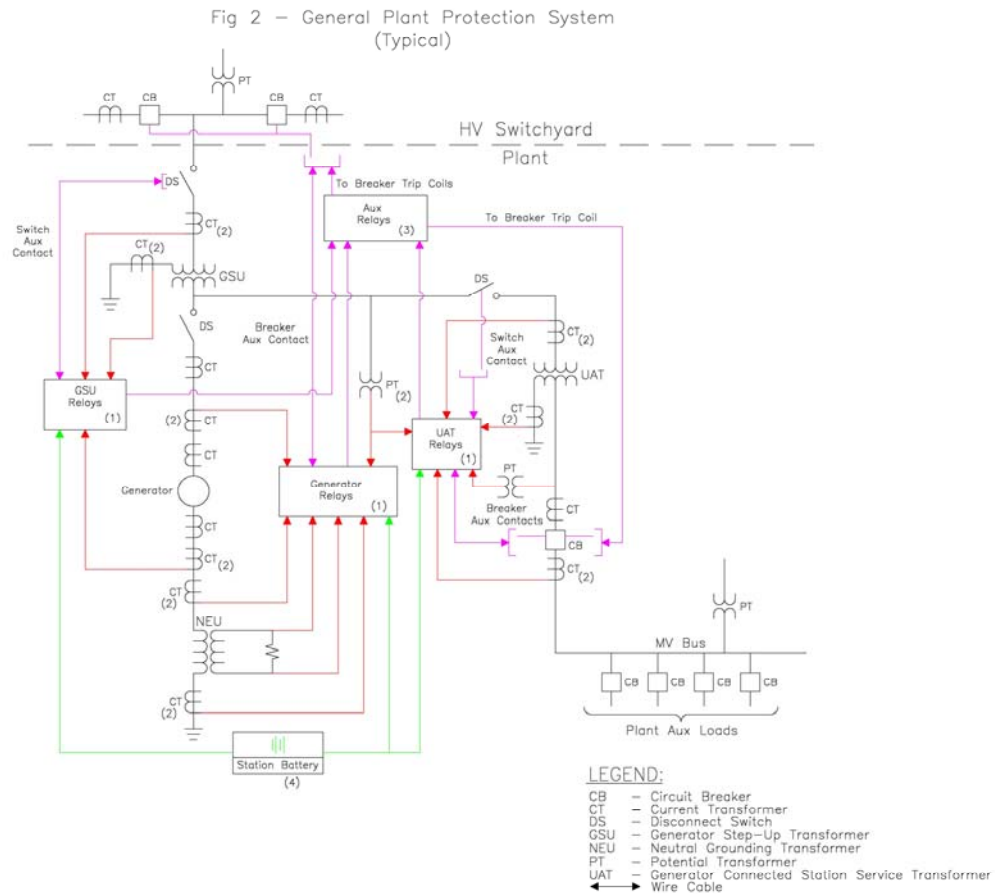
Figures

Figure 1: Typical Transmission System



For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 1 & 2 Legend – Components of Protection Systems

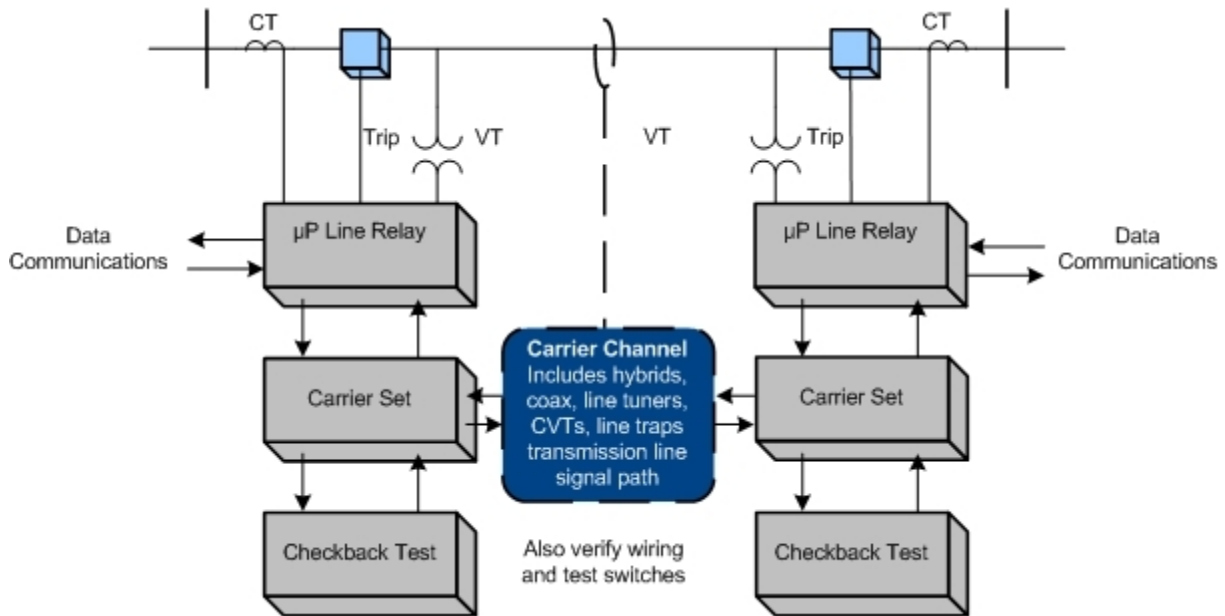
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

[Additional information can be found in References](#)

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line faults, and to avoid over-tripping for faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



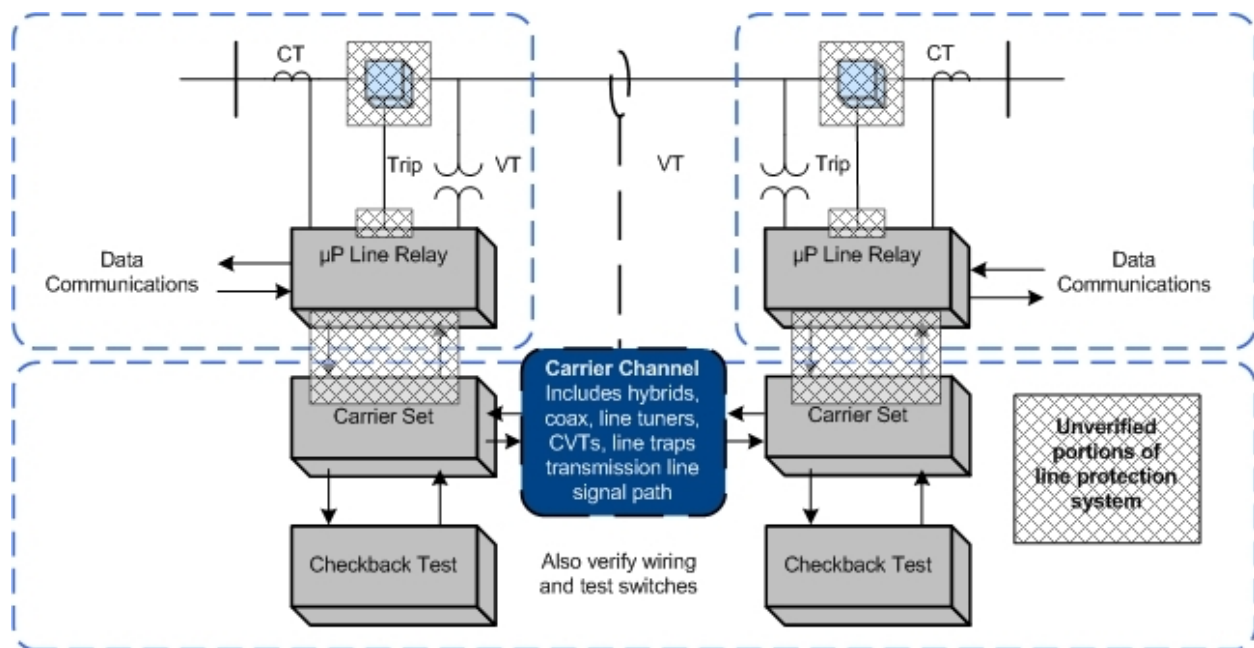
In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.
2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the

contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.

3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-3 does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

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Supplementary Reference and FAQ

PRC-005-3 Protection System Maintenance

~~April~~ October 2013

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1. Introduction and Summary

Note: This supplementary reference for PRC-005-3 is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive, and, when approved, will supersede PRC-005-2.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-3 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the [NERC Glossary of Terms](#) used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- 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.

2.3 Applicability of New Protection System Maintenance Standards

The BES purpose is to transfer bulk power. The applicability language has been changed from the original PRC-005:

“...affecting the reliability of the Bulk Electric System (BES)...”

To the present language:

“...that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).”

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution

Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

NERC's approved definition of Bulk Electric System is:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.

The BES definition is presently undergoing the process of revision.

Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a [June 14, 2007 Informational Filing](#).

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-3 applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Special Protection Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 94 (tripping or trip-free relay), as these devices are tripping relays that respond to the trip signal of the protective relay that processed the signals from the current and voltage-sensing devices.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.6.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

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.

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 a SPS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that

a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES unit within the Balancing Authority Area where the Automatic Reclosing is applied.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

How do I interpret Applicability Section 4.2.6 to determine applicability in the following examples:

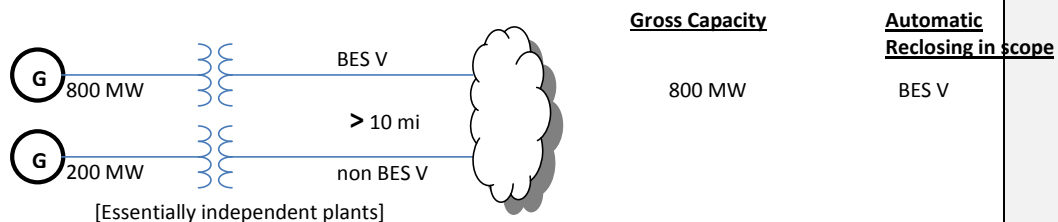
At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.

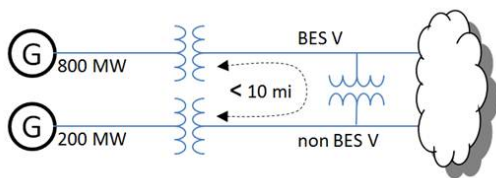


Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



Gross Capacity

1000 MW

Automatic Reclosing in scope

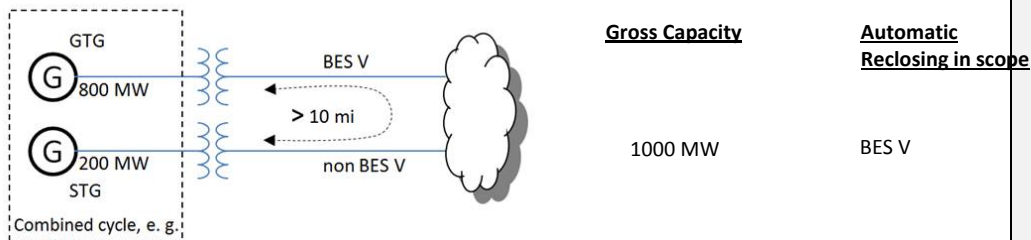
BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.

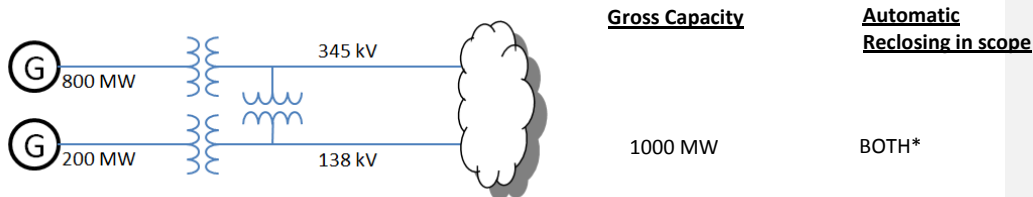


Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.6.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.6.1.



* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.6.2 specify “10 circuit miles”?

As noted in “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.6.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be “one bus away” from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. “One bus away” is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of “Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)”?

Reverse power relays are often installed to detect situations where the transmission source becomes deenergized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not ‘installed for the purpose of detecting’ these faults.

Is a Sudden Pressure Relay an auxiliary tripping relay?

No. IEEE C37.2-2008 assigns the Device No. 94 to auxiliary tripping relays. Sudden pressure relays are assigned Device No. 63. Sudden pressure relays are presently excluded from the standard because it does not utilize voltage and/or current measurements to determine anomalies. Devices that use anything other than electrical detection means are excluded. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent

with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

My mechanical device does not operate electrically and does not have calibration settings; what maintenance activities apply?

You must conduct a test(s) to verify the integrity of any trip circuit that is a part of a Protection System. This standard does not cover circuit breaker maintenance or transformer maintenance. The standard also does not presently cover testing of devices, such as sudden pressure relays (63), temperature relays (49), and other relays which respond to mechanical parameters, rather than electrical parameters. There is an expectation that Fault pressure relays and other non-electrically initiated devices may become part of some maintenance standard. This standard presently covers trip paths. It might seem incongruous to test a trip path without a present requirement to test the device; and, thus, be arguably more work for nothing. But one simple test to verify the integrity of such a trip path could be (but is not limited to) a voltage presence test, as a dc voltage monitor might do if it were installed monitoring that same circuit.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: "A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed."

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: "A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely."

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-

based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft 86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:

- Verify — Determine that the component is functioning correctly.
- Monitor — Observe the routine in-service operation of the component.
- Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing –

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay .

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

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

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action or a Protection System Misoperation attributed to hardware

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

4.1 Frequently Asked Questions:

Why does PRC-005-3 not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-3 requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the “Tables”), and the various components of the definition established for a “Protection System Maintenance Program,” PRC-005-3 establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by “restore” in the definition of maintenance.

The description of “restore” in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity “shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.” Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by “...demonstrate efforts to correct an Unresolved Maintenance Issue...”; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and

management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase “demonstrate efforts to correct” (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a “closed-end process”). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System and Automatic Reclosing Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System and Automatic Reclosing Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.
- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term “Condition-Based-Maintenance” (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the “monitored-basis-time-intervals” existing within the standard, the

explanatory discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

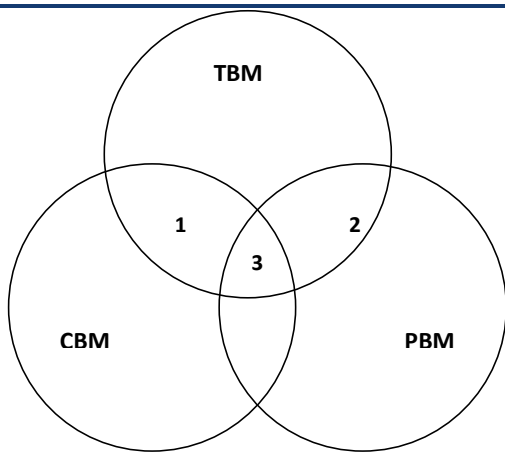
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to **ONLY** perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a “flow chart” of the standard.

We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

-
- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
 - Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

Excessive maintenance can actually decrease the reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.4) of the standard, is it necessary to

provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

“All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center.”

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

“Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability.”

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a combination of time-based and condition-based maintenance. The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-3. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-3.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a "One Calendar Year Interval," the next event would have to occur on or before December 31, 2010.

Please provide an example of "4 Calendar Months".

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number 5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May)

would still be due four months later therefore the activity is due again July. Basically every “four Calendar Months” means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions' section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

-
- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- 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 as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the "Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

-
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
 - Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Special Protection System. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, and Table 4 in the standard specify maximum allowable verification intervals for various generations of Protection Systems and Automatic Reclosing and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in [Figures 1](#) and [2](#) at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. [Figure 2](#) shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and SPS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-3:

-
- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
 - Table 1-1 is for protective relays,
 - Table 1-2 is for the associated communications systems,
 - Table 1-3 is for current and voltage sensing devices,
 - Table 1-4 is for station dc supply and
 - Table 1-5 is for control circuits.
 - Table 2, is for alarms; this was broken out to simplify the other tables.
 - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
 - Table 4 is for Automatic Reclosing.
 - Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
 - This Maintenance activity is the minimum maintenance activity that must be documented.
 - If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
 - After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
 - If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
 - Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
 - An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows

maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-3. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-3, most notable of which is an entity using performance based maintenance methodology. If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc, are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.
2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.
3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or SPS (as opposed to a monitoring task) must be verified as a component in a Protection System.
4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-3 for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-3 is a more economical approach while addressing the reliability requirements of the BES.
5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform

properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).
7. "End-to-end test," as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.
8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.
9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states "...settings are as specified."

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require "...that the relay settings be correct..." because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have "drifted" since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about SPS interfaces between different entities or owners?

As in all of the Protection System requirements, SPS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Special Protection System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the SPS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for SPS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an SPS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an SPS scheme should that occur. Forced trip tests of circuit breakers (etc) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unnecessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval, then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays

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- Neutral overcurrent relay
 - Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A

distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-3 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or to the previous scheduled (on-site) audit date, whichever is longer.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please use a specific example to demonstrate the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld. For example: "Company A" has a maintenance plan that requires its electromechanical protective relays be tested every three calendar years, with a maximum allowed grace period of an additional 18 months. This entity would be required to maintain its records of maintenance of its last two routine scheduled tests. Thus, its test records would have a latest routine test, as well as its previous routine test. The interval between tests is, therefore, provable to an auditor as being within "Company A's" stated maximum time interval of 4.5 years.

The intent is not to require three test results proving two time intervals, but rather have two test results proving the last interval. The drafting team contends that this minimizes storage requirements, while still having minimum data available to demonstrate compliance with time intervals.

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-3, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-3 assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-3 requires performance of maintenance activities that are deemed necessary to detect and correct plausible age and service related degradation of components, such that a properly built and commission tested Protection System will continue to function as designed over its service life.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-3 would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the “Calendar Year” language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a “grace period” without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for “time-interval extensions” or “grace periods” to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. “Maximum time intervals” by their very term negates any “time-interval extension” or “grace periods.” To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was “...no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years...” The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table’s use of the term “Calendar” in the column for “Maximum Maintenance Interval.” The PSMT SDT deemed it necessary to include the term “Calendar” to

facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term “Calendar” to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity’s use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as *ISO 9001-2000, Quality Management Systems — Requirements*; or applicable parts of the NIST Baldrige National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is “the sampling distribution of the sample mean can be approximated by a normal probability distribution.” The Central Limit Theorem states: “In selecting simple random samples of size n from a population, the sampling distribution of the sample mean \bar{x} can be approximated by a normal probability distribution as the sample size becomes large.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

“... whenever we are using a large simple random sample (rule of thumb: $n \geq 30$), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution.” (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

“If samples of size n , when $n \geq 30$, are drawn from any population with a mean μ and a standard deviation σ , the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation.” (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)

“The sample size is large (generally $n \geq 30$)... (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)

“... the normal is often used as an approximation to the t distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection.” (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a “Pass/Fail” format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z \sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1 - \pi) \left(\frac{z}{B} \right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

B = 5%

z = 1.96 (This equates to a 95% confidence level)

π = 4%

Using the equation above, n=59.0.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

B = 5%

z = 1.44 (85% confidence level)

π = 4%

Using the equation above, n=31.8.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

[Performance-Based Program Evaluation Example](#)

[The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.](#)

[In consideration of the use of Performance Based Maintenance \(PBM\), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval \(in years\) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment \(units per year\), or any misoperation attributable to hardware failure or calibration failure found within the entire segment \(1000 units\) during the testing year.](#)

[Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: \$125 \times .04 = 5\$. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations \(attributable to hardware or calibration failure within the testing year\) associated with the entire segment of 1000 units.](#)

[Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: \$63 \times .04 = 2.5\$.](#)

[As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.](#)

Total number of units in the segment	1000	Formatted Table
Failure rate	4.00%	

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

[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.](#)

[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.](#)

[Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Table 4 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.](#)

9.2 Frequently Asked Questions:

I’m a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect

to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure rate (zero failures) while Type "Y" would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment performance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, “reset the clock” on everything you’ve done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that “resetting the clock” should not be construed as interfering with an entity’s routine testing schedule because the “clock-reset” would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is

allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that “replaced relay” will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. $6/200 = 3\%$ failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. $6/100 = 6\%$ failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year ($1000/8$). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. $6/125 = 5\%$ failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year ($1000/7$). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. $6/143 = 4.2\%$ failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year ($1000/6$). After a year, they again find six failures out of the 167 units tested. $6/167 = 3.6\%$ failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures “Control Circuitry” as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity’s specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device

that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year ($1000/12$). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures “voltage and current inputs to the protective relays” as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a “Relay Scheme.” Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT’s or specific PT’s. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays. Under the included definition of “component”:

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

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.*

Example:

Entity has 2000 “Relay Schemes,” all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT’s. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity’s relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their “Voltage and Current Sensing” population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity’s population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. $3/100 = 3\%$ failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. $3/50 = 6\%$ failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year ($1000/16$). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. $3/63 = 4.76\%$ failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year ($1000/14$). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. $3/72 = 4.2\%$ failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. $3/84 = 3.6\%$ failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays “that are designed to provide protection for the BES,” this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its

regularly scheduled cycle. (However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays “out-of-service”. What are our responsibilities when it comes to “out-of-service” devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-3 are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-3. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-3 to remove such component(s). Obviously, prudence would dictate that an “out-of-service” device is truly made inactive. There are no record requirements listed in PRC-005-3 for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-3 requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-3 requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

“R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues.”

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state “...shall demonstrate efforts to correct any identified Unresolved Maintenance Issues...” The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-3 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

These relays are defined as the devices that receive the input signal from the current and voltage sensing devices and are used to isolate a Faulted Element of the BES. Devices that sense thermal, vibration, seismic, pressure, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
 - There is no specific protective relay commissioning test or relay routine test mandated.
 - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the

protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and vars around the entire bus; this should add up to zero watts and zero vars, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "...verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ..." Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay

and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor-based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately “verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays ...” while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "...designed to provide protection for the BES..." then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

While relays that do not respond to electrical quantities are presently excluded from this standard, their control circuits are included if the relay is installed to detect Faults on BES Elements. Thus, the control circuit of a BES transformer sudden pressure relay should be verified every 12 years, assuming its integrity is not monitored. While a sudden pressure relay control circuit is included within the scope of PRC-005-2, other alarming relay control circuits, (i.e., SF-6 low gas) are not included, even though they may trip the breaker being monitored.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes

that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-3 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-3 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-3 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.

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- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-3 applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have an non-BES circuit breaker that is tripped via a Protection System to which PRC-005-3 applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- 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.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, “station batteries” are replaced with “station dc supply” to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-3 is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by “continuity” of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.

- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the

station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example “Conductance Readings” from one manufacturer’s test equipment do not correlate to “Impedance Readings” from a different manufacturer’s test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity

readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries).

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery

containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance “as designed” vs. battery performance “as manufactured.” The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer’s rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trendline against the established baseline. The type of probe and its location (post, connector, etc) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measureable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be “forming” after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an "adequate" ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one

minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-3 is there a maintenance activity to inspect the structural integrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.

Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the “Unintentional dc Grounds” requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a “check-off” of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to “all cells,” is it sufficient to have a documentation method that refers to “all cells,” or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-3 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980’s several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery’s current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The

inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "...depending on the degree of change a performance test, cell replacement or other corrective action may be necessary..." (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or

above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid 1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically

trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to “measure battery cell/unit internal ohmic values.” Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is “...verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline.” This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to “Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.”

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to ‘perform as manufactured.’ It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the “perform as manufactured six-month test” at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the “thermal runaway test” at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float

(charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to “verify station dc supply voltage” every “4 calendar months” (see table 1-4(a)), the owner can install a monitoring and alarming device “with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure” and “no periodic verification of station dc supply voltage is required” (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install “electrolyte level monitoring and alarming in every cell” and “unintentional dc ground monitoring and alarming” (see second and third rows of table 1-4(f)), the owner will have to “inspect electrolyte level and for unintentional grounds” every “4 calendar months” (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to “Protection System Control Circuitry”, rather than those portions of the table applicable to communications equipment.

What is meant by “Channel” and “Communications Systems” in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the “channel” as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting “performance criteria.” What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These

limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe “form-b” contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "...does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature autoreclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated ~~supervisor~~supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage

supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that is not part of an SPS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that is part of an SPS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the SPS, and must be verified.

15.9 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.9.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics

-
- Maintenance records
 - Logs (operator, substation, and other types of log)
 - Inspection forms
 - Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
 - Check-off forms (paper or electronic)
 - Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 (“Special Protection System Misoperation”). Can I also use it to show compliance for this Standard, PRC-005-3?

Maintaining evidence for operation of Special Protection Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-3.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

References

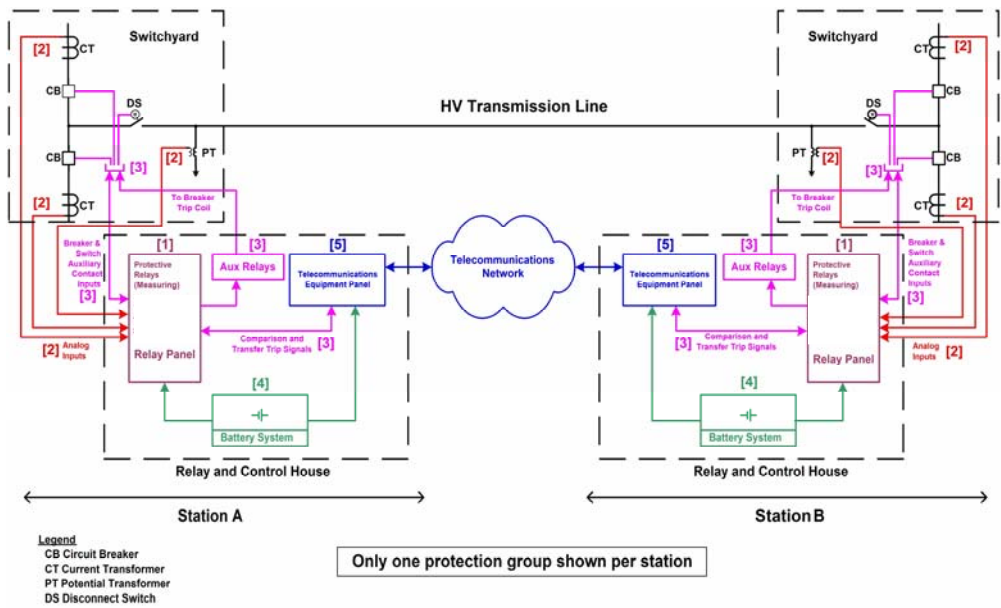
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PSMT SDT References

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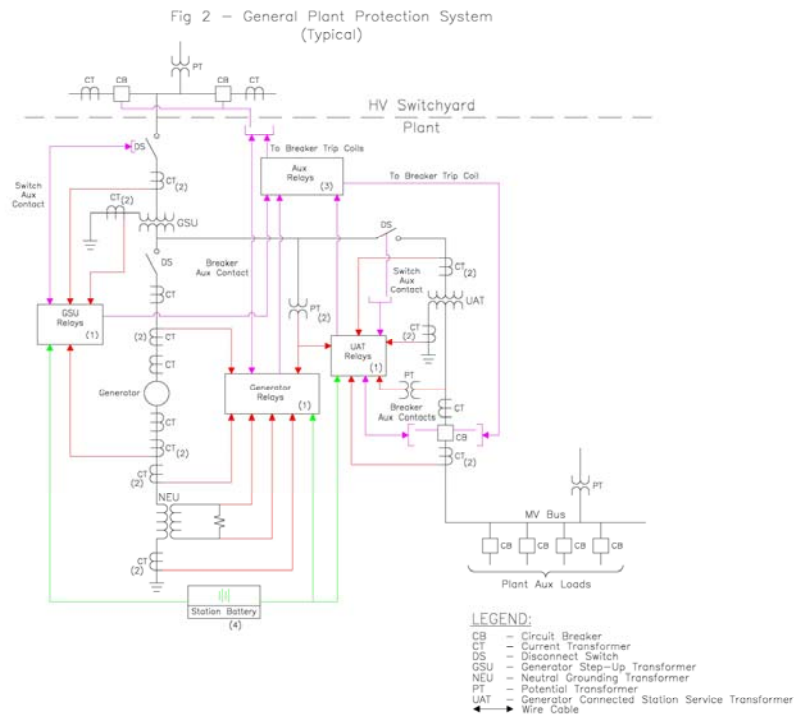
Figures

Figure 1: Typical Trip Transmission System



For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see [Figure 1 & 2 Legend – components of Protection Systems](#)

Figure 1 & 2 Legend – Components of Protection Systems

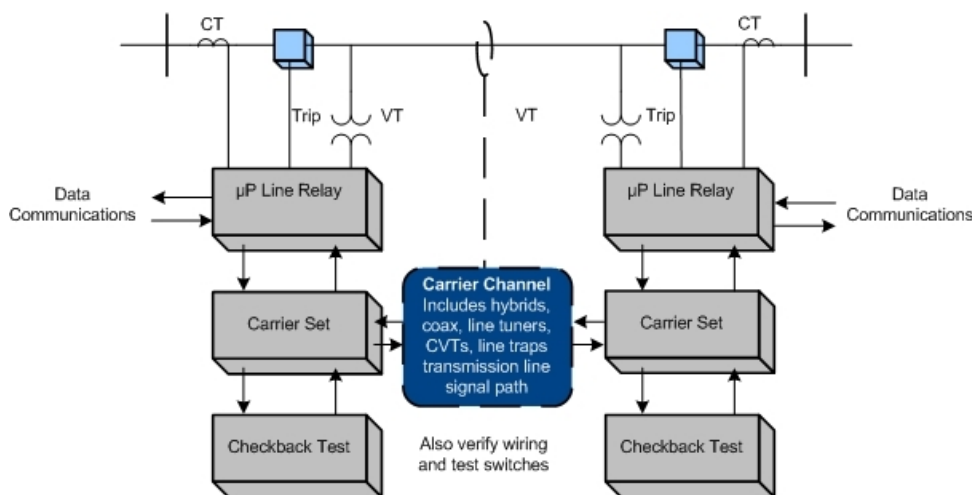
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

[Additional information can be found in References](#)

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line Faults, and to avoid over-tripping for Faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



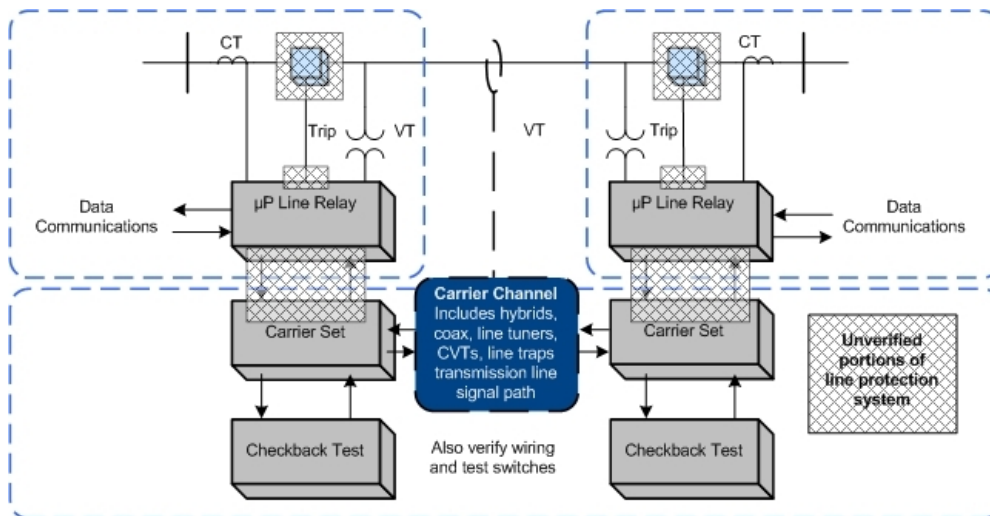
In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.
2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the

contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.

3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-3 does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

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Standards Announcement

Project 2007-17.2 Protection System Maintenance and Testing Phase 2 (Reclosing Relays) PRC-005-3

A Final Ballot is now open through October 25, 2013

Now Available

A final ballot for **PRC-005-3 – Protection System and Automatic Reclosing Maintenance** is open through **8 p.m. Eastern on Friday, October 25, 2013.**

Background information for this project can be found on the [project page](#).

Instructions

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking [here](#).

Next Steps

Voting results for the standard will be posted and announced after the ballot window closes. If approved, the standard will be submitted to the Board of Trustees for adoption.

Standards Development Process

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

*For more information or assistance, please contact Wendy Muller,
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Standards Announcement

Project 2007-17.2 Protection System Maintenance and Testing Phase 2 (Reclosing Relays) PRC-005-3

Final Ballot Results

[Now Available](#)

A final ballot for **PRC-005-3 – Protection System and Automatic Reclosing Maintenance** concluded at **8 p.m. Eastern on Friday, October 25, 2013.**

This standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the [Ballot Results](#) page provides a link to the detailed results for the ballot.

Approval
Quorum: 85.71%
Approval: 85.38%

Background information for this project can be found on the [project page](#).

Next Steps

The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

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

*For more information or assistance, please contact [Wendy Muller](#) (via email),
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- Current Ballots
- Ballot Results
- Registered Ballot Body
- Proxy Voters

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Ballot Results	
Ballot Name:	Project 2007-17.2 PRC-005-3 Final Ballot
Ballot Period:	10/16/2013 - 10/25/2013
Ballot Type:	Final Ballot
Total # Votes:	348
Total Ballot Pool:	406
Quorum:	85.71 % The Quorum has been reached
Weighted Segment Vote:	85.38 %
Ballot Results:	A quorum was reached and there were sufficient affirmative votes for approval

Summary of Ballot Results										
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Negative Vote without a Comment	Abstain	No Vote	
			# Votes	Fraction	# Votes	Fraction				
1 - Segment 1	107	1	63	0.788	17	0.213	0	9	17	
2 - Segment 2	9	0.5	4	0.4	1	0.1	0	3	1	
3 - Segment 3	95	1	60	0.857	10	0.143	0	12	13	
4 - Segment 4	33	1	20	0.909	2	0.091	0	5	6	
5 - Segment 5	92	1	55	0.764	17	0.236	0	8	12	
6 - Segment 6	53	1	34	0.773	10	0.227	0	3	6	
7 - Segment 7	0	0	0	0	0	0	0	0	0	
8 - Segment 8	6	0.3	3	0.3	0	0	0	0	3	
9 - Segment 9	2	0.2	2	0.2	0	0	0	0	0	
10 - Segment 10	9	0.9	9	0.9	0	0	0	0	0	
Totals	406	6.9	250	5.891	57	1.01	0	40	58	

Individual Ballot Pool Results										

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	COMMENT RECEIVED
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Negative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Abstain	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	SUPPORTS THIRD PARTY COMMENTS
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Matthey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENT RECEIVED
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Abstain	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
				SUPPORTS

				THIRD PARTY COMMENTS
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Abstain	
3	Ameren Services	Mark Peters	Affirmative	
3	American Public Power Association	Nathan Mitchell	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	City of Vineland	Kathy Caignon		
3	Cleco Corporation	Michelle A Corley	Negative	COMMENT RECEIVED
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Abstain	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Abstain	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Abstain	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	Manitowoc Public Utilities	Thomas E Reed		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson	Affirmative	

3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	COMMENT RECEIVED
4	Detroit Edison Company	Daniel Herring	Abstain	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrus Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer		
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	

4	South Mississippi Electric Power Association	Steven McElhaneey	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Abstain	
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Buckeye Power, Inc.	Paul M Jackson		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	COMMENT RECEIVED
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans		
5	Dominion Resources, Inc.	Mike Garton	Negative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	El Paso Electric Company	Gustavo Estrada	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	COMMENT RECEIVED
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	

5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Abstain	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Leo Staples	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	David Ramkalawan	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Abstain	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	COMMENT RECEIVED
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	

6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Queryy	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	COMMENT RECEIVED
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS
8		Edward C Stein	Affirmative	
8		Merle Ashton		
8		Roger C Zaklukiewicz		
8	Foundation for Resilient Societies	William R Harris		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	



10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

[Legal and Privacy](#)

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Exhibit I

Standard Drafting Team Roster

Standard Drafting Team Roster

Project 2007-17.2 Protection System Maintenance and Testing Phase 2 (Reclosing Relays)

Member	Bio
<p>John Anderson Principal Engineer</p> <p>Xcel Energy, Inc. 1518 Chestnut Avenue N. 2nd Floor Minneapolis MN 55403</p> <p>Business: (612) 630-4630</p> <p>john.b.anderson@xcelenergy.com</p>	<p>John Anderson is presently a Principal Engineer with Xcel Energy and is responsible for the development and implementation of the company's power plant electrical distribution system equipment maintenance programs including those for plant protective relay systems, power transformers, circuit breakers and battery systems. He has served in this capacity since 1998. Prior to taking on this fleet wide coordination role, he served for 8 years as an Electrical System Engineer at Xcel Energy's Monticello Nuclear Generating Station with responsibilities including coordination of the plant's protection system testing program. During this time, Mr. Anderson earned a Senior Reactor Operator Certification for the plant. Prior to joining Northern State Power Company in 1990, Mr. Anderson completed the Navy Nuclear Propulsion Officer training program and served as a Nuclear Propulsion Plant Watch Officer and Electrical Distribution Officer aboard the USS ENTERPRISE (CVN-65). He holds a BSEE from the University of Minnesota.</p>
<p>Merle Ashton Substation Maintenance Supervisor</p> <p>Tri-State G & T Association, Inc. 12496 Rd 23 Cortez CO 81321</p> <p>Business: (970) 759-6139</p> <p>rashton@tristategt.org</p>	<p>Rick Ashton is presently a Substation Maintenance Supervisor for Tri-State Generation and Transmission Assn., Inc. Rick has held this position since 2006; prior to 2006 Rick was a Substation Technician for this same company since 1981. As a Substation Technician, Rick's primary responsibility was the maintenance of Protection System components and other equipment within the substation yard and control house. Relays (protective and otherwise), batteries, transformers, circuit breakers, regulators, switches were all within his area of influence. These years of hands-on experience provided Rick opportunities to observe and investigate many different equipment failures; to use a variety of test equipment, and employ many test methods. As owner/operator of relaytech.com, Rick has authored many titles of "how-to" books that assist in the training of relay technicians. Rick travels to utilities, testing companies, and consulting firms upon request for training relay technicians, and other personnel. Rick imparts his</p>

	<p>overall knowledge of Protection Systems, their characteristics and interactions, as well as the math and theory behind it all, providing technical personnel with a better working understanding of the entire substation.</p>
<p>Forrest D. Brock Superintendent of Station Services</p> <p>Western Farmers Electric Cooperative 701 NE 7th Street PO Box 429 Anadarko, Oklahoma, 73005-0429</p> <p>Business: (405) 247-4360</p> <p>f_brock@wfec.com</p>	<p>Forrest Brock is the Superintendent of Station Services at Western Farmers Electric Cooperative – a generation and transmission cooperative serving 22 distribution cooperative members in Oklahoma and New Mexico. Forrest has 23 years of protection and control experience earned through his service as a relay technician and supervisor, along with two years serving as Transmission Compliance Specialist prior to his promotion to department superintendent in 2012. In 2009, Forrest began serving as a participating and contributing observer on the Standard Drafting Team for Project 2007-17 and became an official SDT member in 2011. Forrest is also a member of the Standard Drafting Team for Project 2007-06 System Protection Coordination developing NERC Reliability Standard PRC-027-1, and represents Cooperatives as a member of the NERC System Protection and Control Subcommittee (SPCS).</p>
<p>Aaron Feathers Principal Engineer</p> <p>Pacific Gas and Electric Company 487 W. Shaw Avenue, Building A Fresno, CA 93704</p> <p>Business: (559)263-5011</p> <p>aaron.feathers@pge.com</p>	<p>Aaron Feathers is presently a Principal Engineer in System Protection at Pacific Gas and Electric Company, where he has been employed since 1992. He has 20 years of experience in the application of protective relaying and control systems on transmission systems. Aaron's current job responsibilities include design standards, wide area RAS support, NERC PRC compliance, and relay asset management support. He has a BSEE degree from California State Polytechnic University, San Luis Obispo and is a registered Professional Engineer in the State of California. He is also a member of IEEE and is on the Western Protective Relay Conference planning committee.</p>
<p>Samuel Francis System Protection Specialist</p> <p>Oncor Electric Delivery 115 W. 7th Street Suite 3114 P. O. Box 970 Fort Worth TX 76101</p>	<p>Samuel B. Francis is presently a System Protection Specialist for Oncor Electric Delivery. Sam has over 35 years experience working for Oncor Electric Delivery with 30 years of that time having been spent in the area of System Protection in which he has served on several taskforces and committees that have been responsible for determining maintenance and testing procedures for the Oncor Protection Systems. For the past 7 years, Mr. Francis has been a member of the NERC System Protection and Control Subcommittee (SPCS) formally the System Protection and Control</p>

<p>Business: (817) 215-6920 samuel.francis@oncor.com</p>	<p>Task Force (SPCTF). Mr. Francis is also a member of the NERC Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT) developing the NERC Reliability Standard PRC-005-2. Sam has also been a member of the NERC System Protection Coordination Standard Drafting Team (SPCSDT) since its formation in 2008 developing NERC Reliability Standard PRC-027-1. Mr. Francis holds a BSEE from Brigham Young University and is a registered Professional Engineer in the State of Texas.</p>
<p>Ervin David Harper I & E Specialist NRG Texas Maintenance Services 12307 Kurland Houston TX 77034 Business: (713) 545-6019 david.harper@nrgenergy.com</p>	<p>Ervin David Harper is presently I&E specialist for NRG Maintenance Services responsible for protective system maintenance and testing and system and equipment fault analysis. He has over 30 years experience in the maintenance and testing of generation station equipment including generators, transformers, switchgear, motors and protection and control systems.</p>
<p>James M. Kinney Senior Engineer FirstEnergy Corporation 76 South Main Street Akron, OH 44308 Business: (419) 521-6252 kinneyj@firstenergycorp.com</p>	<p>James M. Kinney is presently a Senior Engineer, Transmission and Substation Services at FirstEnergy Corporation. He has over 20 years of experience in the power industry including engineering, operations and maintenance. Since 2000, he has been responsible for substation commissioning as well as substation maintenance and testing programs at FirstEnergy Corporation. He is a senior member IEEE, a member of the IEEE Power and Energy Society, an individual member of the IEEE Standards Association, and also an individual member of Cigre'. He holds a BSEE from The Ohio State University and is a registered Professional Engineer in the State of Ohio.</p>
<p>Mark Lukas T&S Engineering, Real Time Analysis Manager Commonwealth Edison Co. Two Lincoln Centre 9th Floor Oakbrook Terrace IL 60181-4260 Business: (630) 576-6891</p>	<p>Mark Lukas has worked for ComEd in various Protection and Control roles for most of his 36 years. Upon graduating from Purdue University-Calumet in 1979, early responsibilities were in the Operational Analysis (Field Testing) Department performing Substation Relay and Equipment installations, maintenance, and troubleshooting. Subsequent moves were into manager roles in various Operational Analysis sections and then managing the Relay and Protection Engineering - SCADA Standards group. Mark has currently been managing the Relay and Protection Engineering - Real Time Analysis group for 12 years. Mark's current</p>

<p>mark.lukas@comed.com</p>	<p>duties/responsibilities include 7x24 operational analysis support for Transmission & Substation automatic operations, abnormal system configuration evaluations, as well as abnormal protection system conditions evaluations.</p>
<p>Kristina Marriott Senior Project Manager & Application Consultant</p> <p>ENOSERV 7708 East 106th Street Tulsa, Ok 74133</p> <p>Business: (918) 622-4530 x 110</p> <p>kmariott@enoserv.com</p>	<p>Kristina Marriott has been the Senior Project Manager at ENOSERV for over 3 years and has worked for ENOSERV over 5. Her primary job consists of consulting & data application projects. Many of her projects have been geared to Transmission and Distribution, where she works with Engineering and Technical groups to develop, implement, and support maintenance Programs for Protection System components and other equipment utilizing multiple systems & applications. Prior to her Project Manager position, she supported multiple utilities in troubleshooting and maintaining Protective Relays. She has extensive knowledge and experience with asset management, business plans, policies, regulatory compliance, and continues to take an extreme interest in Protection and Control.</p>
<p>Al McMeekin Standards Development Advisor</p> <p>NERC 3353 Peachtree Rd. NE Suite 600, North Tower Atlanta, GA 30326</p> <p>Business (803) 530-1963</p> <p>al.mcmeekin@nerc.net</p>	<p>Al McMeekin is the NERC Staff Advisor for Project 2007-17 (Protection System Maintenance and Testing – PRC-005). Prior to joining NERC in 2009, Mr. McMeekin worked at South Carolina Electric & Gas Company for 29 years as an engineer in distribution operations and engineering, and in Transmission Operations Planning. Al participated in SCE&G’s ERO Working Group to ensure compliance with NERC standards; and represented SCE&G on various national, regional, and subregional groups. Mr. McMeekin was a member of the SERC Operating Committee and served as Chair of the SERC Operations Planning Subcommittee. Al was a member of the SERC Standards Committee and the SERC Available Transfer Capability Working Group. He also served as Chair of the VACAR South Reliability Coordinator Procedures Working Group, and was a member of Project 2006-03 (System Restoration and Blackstart – EOP-005 & EOP-006) Standards Drafting Team. Al holds a BSAgE degree from Clemson University and is a registered Professional Engineer in South Carolina.</p>
<p>Michael Palusso Manager Transmission/Substation FERC/NERC/CAISO/CPUC Compliance</p>	<p>Mike Palusso has been part of the Southern California Edison company for 30 years. Throughout his career Mike held numerous positions in the substation area culminating as the Manager for Power Utility Substation Equipment and Relay. Mike is currently the Manager for Transmission/Substation Maintenance &</p>

<p>Southern California Edison (SCE) 3 Innovation Way Pomona, CA, 91768</p> <p>Business: (909) 274-3460 Michael.Palusso@sce.com</p>	<p>Inspection Compliance. His responsibilities encompass compliance for NERC/WECC/CAISO, as well as CPUC compliance reporting for protection and control systems, substation equipment, vegetation management, and transmission line equipment. Mike also represents SCE’s interests on the CAISO Transmission Maintenance Coordination Committee.</p>
<p>Charles W. Rogers Principal Engineer</p> <p>Consumers Energy 1945 W. Parnall Road Jackson, Michigan 49201</p> <p>Business: (517) 788-0027 Charles.Rogers@cmsenergy.com</p>	<p>Charles Rogers is a Principal Engineer at Consumers Energy, where he has been employed since 1978. For the bulk of his career, has been responsible for application of protective relaying to the transmission and distribution systems, and is currently responsible for managing compliance to NERC Standards for the "wires" portion of Consumers Energy. He chaired the NERC System Protection and Control Task Force from its inception in 2004 through May 2008, and continues to be a member of its successor group, the NERC System Protection and Control Task Force, and was a member of the NERC Planning Committee in 2009. He chaired the ECAR investigation into the August 2003 blackout, chaired the ECAR Protection Panel for several years, and chaired the RFC Protection Subcommittee from its inception in 2006 through 2012. At NERC, he was a member of the "Phase II Standard Drafting Team" in 2005-2006, chaired the standard drafting team that developed PRC-023-1, and currently chairs the standard drafting teams assigned to Projects 2007-17 (Protection System Maintenance) and 2010-13 (addressing FERC Order 733). At RFC, he also chaired the standard drafting team that developed PRC-002-RFC. Charles is also a member of IEEE Standards Coordinating Committee 21, and was a key member of the working groups that developed IEEE 1547, IEEE 1547.2, and IEEE 1547.4. He received his BSEE degree from Michigan Technological University in 1978. He is a registered professional engineer in the State of Michigan, and is a Senior Member of IEEE.</p>
<p>John E. Schechter Manager, Protection & Control Engineering Office</p> <p>American Electric Power 700 Morrison Road Gahanna OH 43230</p> <p>(614) 552-1908</p>	<p>John Schechter is Manager of American Electric Power’s Protection & Control Engineering office in Columbus, Ohio. John has been with American Electric Power (AEP) or its operating companies since 1980. He has held many positions with increasing responsibility in substation operation, construction, maintenance or engineering spanning 32 years and has also held supervisory or managerial positions in distribution line design, distribution service dispatching, overhead and underground distribution maintenance and construction, and transmission line asset management.</p>

<p>jeschechter@aep.com</p>	<p>Following the 2003 blackout, John was named to the NERC Transmission Vegetation Management (VM) task force to draft the new vegetation management standard. He was named to the NERC PRC-005-2 revision drafting team in 2011. John received the B.S.E.E. degree in electrical engineering from the University of Cincinnati, the M.S.E.E. degree in electric power systems engineering from The Ohio State University, and the M.B.A. degree from the University of Notre Dame. He is a registered professional engineer in the states of Indiana and Ohio.</p>
<p>William D. Shultz Engineering Manager</p> <p>Southern Company Generation 42 Inverness Center Parkway Mail Bin B425 Birmingham AL 35242</p> <p>Business: (205) 992-5526</p> <p>wdshultz@southernco.com</p>	<p>Bill Shultz is presently Engineering Manager, Electrical Services and Field Support, Technical Services of Southern Company Generation. He has 29 years of experience in Generating Plant Technical Services, including protective equipment application, start-up commissioning, and maintenance of protective relaying and control systems for electric power generating plants. His work experience includes the commissioning and maintenance of the control and protection of static excitation systems, variable speed drives, and emergency generation. He is active in Southern Company reliability standards compliance efforts as well as being involved in regional and national organizations responsible for utility reliability standards. He holds a BSEE from the University of Tennessee, a MSEE from Auburn University, and is a registered Professional Engineer in the State of Alabama.</p>
<p>Eric Udren Executive Advisor</p> <p>Quanta Technology, LLC 1395 Terrace Drive Pittsburgh, PA 15228</p> <p>Business: (412)-596-6959</p> <p>eudren@quanta-technology.com</p>	<p>Eric A. Udren has a 43 year distinguished career in design and application of protective relaying, utility substation control, and communications systems. He developed protection software for the world's first computer based transmission line relaying system, as well as for the world's first substation P&C system based on local area network communications. He has worked with major utilities to develop new substation protection, control, data communications, SPS, and wide area monitoring and protection system designs, including major projects for substation integration based on IEC 61850. He currently serves as Executive Advisor with Quanta Technology, LLC of Raleigh, NC with his office in Pittsburgh, PA. Eric is IEEE Fellow, Chair of the Relaying Communications Subcommittee of the IEEE Power System Relaying Committee (PSRC) and chairs two standards working groups of PSRC. He is Technical Advisor to the US National Committee of IEC for protective relay standards from TC 95; and is member of the IEC TC 57 WG 10 that develops IEC 61850 power systems communications</p>

	<p>and integration protocol. Eric serves on the NERC System Protection and Control Subcommittee (SPCS), as well as the subject PRC-005-2 Drafting Team. He has written and presented over 90 technical papers and book chapters.</p>
<p>Scott Vaughan, P.E. Electrical Engineering Manager</p> <p>Roseville Electric 2090 Hilltop Circle Roseville, CA 95747</p> <p>Business: (916) 774-5604</p> <p>svaughan@roseville.ca.us</p>	<p>Scott Vaughan is currently the Electrical Engineering Manager of Roseville Electric. He has over 18 years of industry experience. In his current position, Mr. Vaughan is responsible for the operation, design and construction of electrical facilities within the City of Roseville. Throughout his career, he has held positions as a protection, generation facility design, and substation design engineer. He has worked as the Subject Matter Expert (SME) for Roseville Electric since 2007 and is currently the responsible engineer for compliance with the NERC mandatory reliability standards relating to the city’s registration as a Distribution Provider, Generator Operator and Generator Owner. Mr. Vaughan holds a BSEE from the California Polytechnical State University at San Luis Obispo, a MBA from Golden Gate University and is a registered engineer in the State of California.</p>
<p>Mathew J. Westrich, P.E. Assistant Manager Asset Maintenance</p> <p>American Transmission Co. (ATC)</p> <p>Business: 906-779-7901</p> <p>mwestrich@atcllc.com</p>	<p>Mathew Westrich is presently the Assistant Manager Asset Maintenance for American Transmission Company. Previously Matt held positions as Substation Maintenance Engineer and Asset Manager with ATC. He also worked for Wisconsin Energies as a relay testing technician since 1982. He has over 30 years’ experience in Protection, Commissioning and Maintenance. He is a licensed P.E. with the State of Wisconsin.</p>
<p>Philip B. Winston Chief Engineer, Protection and Control Applications</p> <p>Southern Company 62 Like Mirror Road Bin # 50061 Forest Park, Georgia 30297</p> <p>Business: (404) 608-5989</p> <p>pbwinsto@southernco.com</p>	<p>Philip B. Winston is presently the Chief Engineer, Protection and Control Applications for Southern Company Transmission. Previously he was the Manager, Protection and Control Applications with Georgia Power Company since 1991. With over 40 years experience in Protection, Operations, Engineering, and Maintenance, he has been active in Southern Company standardization efforts as well as being involved in regional and national organizations responsible for utility standards and disturbance analysis. He is a past Chairman of the IEEE/ Power System Relaying Committee, a past Chair of the PSRC Systems Protection and the Line Protection Subcommittees, presently the Standards Coordinator for IEEE PSRC and serves on the IEEE</p>

	<p>Standards Association Standards Board, NesCom, ProCom, and Awards Committee. He is the Vice Chair of the NERC SPCS, and serves on several NERC Standard Drafting Teams including the Chair of Project 2007-06 System Protection Coordination SDT. He holds a BSEE from Clemson University, a MSEE from Georgia Tech, and is a registered Professional Engineer in the State of Georgia.</p>
<p>John Zipp Senior Staff Engineer</p> <p>ITC Holdings 27175 Energy Way Novi MI 48377</p> <p>Business: (248) 946-3289</p> <p>jzipp@itctransco.com</p>	<p>John Zipp has over 30 years of transmission system protection experience. He has 27 years of experience at Consumers Energy in the System Protection area. He spent 20 years as the supervisor of the Transmission System protection group directing protection system design, setting, and managing the protective system maintenance program at Consumers Energy. He was System Control Supervisor for 4 years directing the south control room in Jackson Michigan. He is presently a Senior Staff engineer at ITC Holdings directing the Relay Engineering department since 2007. He is an IEEE Senior member and was a member of the Power System Relaying Technical Committee in the IEEE for 17 years serving many working groups and as the Chair of the Line Protection committee. He has a BSEE degree from Michigan Tech and is a Registered professional Engineer in the State of Michigan.</p>