NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Meeting Notes
Project 2007-06 System Protection Coordination Standard Drafting Team

August 27-29, 2013

Oncor Headquarters
Ft. Worth, TX

Administrative

1. **Introductions**

   The meeting was brought to order by Chair, Phil Winston at 8:00 a.m. CT on Tuesday, August 27, 2013. Building and safety information/logistics were provided by Sam Francis of Oncor. Each participant was introduced. Those in attendance were:

Name	Company	Member/ Observer	In Person	Conference Call/Web
Philip Winston, Chair	Southern Company	Member	X	
Bill Middaugh, Vice Chair	Tri-State G & T Association, Inc.	Member	X	
David Cirka	National Grid	Member		X
Samuel Francis	Oncor	Member	X	
William Waudby	Consumers Energy	Member	X	
Kevin Wempe	Kansas City Power & Light	Member		X
Ken Swift	Oncor	Observer	X	
Chris Lightsey	Luminant	Observer	X	
Jeffrey Iler	American Electric Power	Member	X	
Al McMeekin	NERC Staff	Member	X	

2. **Determination of Quorum**

   The rule for NERC Standard Drafting Team (SDT or team) states that a quorum requires two-thirds of the voting members of the SDT. Quorum was achieved as seven of the eight members were present.

3. **NERC Antitrust Compliance Guidelines, Public Announcement, and Participant Conduct Policy**

   The NERC Antitrust Compliance Guidelines, public announcement, and Participant Conduct Policy were delivered.

4. **Review team roster**

   The team reviewed the roster and confirmed that it was accurate and up to date.

Agenda

1. **Discuss developments since last meeting**

   Mr. Winston thanked the team for completing their assignments and reiterated the results of the email ballot.

2. **Finalize responses to comments**

   The SDT completed the responses to comments.

3. **Review and revise current version(s) of draft standard and other documents for Quality Review submission**

   The SDT reviewed and approved the revised standard. Refer to the attached documents for specifics.

4. **Next steps**

   Mr. McMeekin will review each document to ensure all changes made to the standard are consistent throughout all the documents. Mr. Mcmeekin will prepare all documents and submit them for Quality Review the week of September 9, 2013. The finalized documents will be posted for a 45-day formal comment and ballot during the week of September 16, 2013.

5. **Future meeting(s)**

   Tentative – the week of December 2, 2013.

6. **Adjourn**

   The SDT thanked Oncor for its hospitality and the Chair adjourned the meeting at 4:00 p.m. CT on Thursday, August 29, 2013.

Standard Development Timeline

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

Development Steps Completed

1. Draft 1 of SAR posted for comment June 11, 2007 – July 10, 2007.
2. SAR approved on August 13, 2007.
3. First posting of revised standard PRC-001-2 on September 11, 2009.
4. Transitioned from a revision of PRC-001-1 to development of PRC-027-1 based on industry comments, Quality Review feedback, and consideration of FERC directives relative to the existing requirements of PRC-001-1.
5. Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012.
6. Draft 2 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from November 16 – December 17, 2012.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPC SDT) created a new results-based standard, PRC-027-1,with the stated purpose 'to coordinate Protection Systems for ~~Interconnected~~Interconnecting Elements, such that Protection System components operate in the ~~desired~~ intended sequence during Faults.' This standard incorporates and clarifies the coordination aspects of Requirements R2 and R3 from PRC-001-2 (formerly R3 and R4 of PRC-001-1). The SPC SDT is requesting a posting for stakeholder comments for a 30-day formal comment period with a parallel successive ballot.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period with Parallel Successive Ballot	June 2013
Conduct Recirculation Ballot	August 2013
BOT Adoption	November 2013

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is 12 months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. For ~~Interconnected~~Interconnecting Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 – PRC-027-1	New

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.

The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

~~Interconnected~~ Interconnecting Element: A BES Element that electrically joins ~~f~~Facilities ~~owned by~~:

a) owned by separate Registered Entities, or

b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Protection System Coordination Study: A study that ~~demonstrates~~ documents existing or proposed Protection Systems operate in the ~~desired~~ intended sequence for clearing Faults.

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

A. Introduction

1. **Title:** **Protection System Coordination for Performance During Faults**

2. **Number:** PRC-027-1

3. **Purpose:** To coordinate Protection Systems for ~~Interconnected~~ Interconnecting Elements, such that Protection System components operate in the ~~desired~~ intended sequence during Faults.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider (that own Protection Systems identified in the Facilities section 4.2 below)

~~4.2.~~ 4.2

Facilities:

~~4.3. For the purpose of the~~These ~~requirements contained herein~~ are applicable to~~, the following Protection Systems owned by each Functional Entity in 4.1~~ that owns ~~above are those to which these requirements are applicable.~~

Protection Systems:

a) ~~-~~installed for the purpose of detecting Faults on Interconnecting~~ed~~ Elements,

~~of the BES~~ and

b) that require coordination for isolating those faulted Elements

~~that require coordination for isolating those faulted Elements~~

5. **Background:**

On December 7, 2006, the NERC Planning Committee approved the assessment of Reliability Standard PRC-001 – System Protection Coordination, prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF noted problems with the applicability to entities and vagueness of requirements in the existing PRC-001-1 reliability standard. The SPCTF concluded that the deficiencies of Reliability Standard PRC-001-1 were magnified by having requirements that addressed coordination of protection functions and capabilities in the operating and planning timeframes. Consequently, the SPCTF recommended that the requirements for the operating horizon and planning horizon be clearly delineated, and possibly divided into two standards.

The NERC Standards Committee approved a Standard Authorization Request that included the modifications noted by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address all issues identified by the

SPCTF assessment of PRC-001-1. The SPC SDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focused their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and clarified in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

> *"To coordinate Protection Systems for ~~Interconnected~~Interconnecting Elements, such that Protection System components operate in the ~~desired~~ intended sequence during Faults."*

~~Additionally, the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21-C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination.~~

PRC-001-1 contained a non-specific training requirement (Requirement R1), three operating time frame requirements (Requirements R2, R5 and R6), and two planning requirements (Requirements R3 and R4). The SPC SDT transferred the responsibility of addressing the operating Requirements R2, R5, and R6 to the drafting team for Project 2007-03 Real-time Operations, charged with revising the TOP group of reliability standards. The Project 2007-03 drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they addressed data and data requirements that are now included in Reliability Standard TOP-003-2. The NERC Board of Trustees adopted Reliability Standards TOP-003-2 and PRC-001-2 on May 9, 2012.

The SPC SDT revised PRC-001-2. Revisions include the removal of Requirements R2 and R3 (formerly Requirements R3 and R4 of PRC-001-1). These two legacy requirements are being retired because the aspects of coordination they address are incorporated in the proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The SPCSDT believes the training aspects of Requirement R1 would be more appropriately addressed by the PER group of Reliability Standards. Consequently, the drafting team has recommended via the NERC Issues Database that the future drafting team charged with revising PER-005-1 incorporate the reliability objective of Requirement R1 into the revised standard. Until that occurs, Requirement R1 of PRC-001-2 must remain in the standard. In an effort to improve PRC-001-2 until it can be fully retired, the drafting team has provided a measure to accompany Requirement R1. The Applicability section was also updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)

Other Aspects of Coordination of Protection Systems Addressed by Other Projects:

Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects~~.~~:

- Underfrequency Load shedding programs are addressed in PRC-006-1. Generator performance during frequency excursions is being addressed in PRC-024-1 by Project 2007-09 Generator Verification.
- Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed in PRC-024-1 by Project 2007-09, Generator Verification.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is being addressed in PRC-019-1 by Project 2007-09, Generator Verification.
- Transmission relay loadability is addressed in PRC-023-2.
- Generator relay loadability will be addressed in PRC-025-1 by ~~Phase 2 of Relay Loadability: Generation, in~~ Project 2010-13.2, Phase 2 of Relay Loadability: Generation.
- Protective relay response during power swings will be addressed by ~~Phase 3 of~~ Project 2010-13.3, Phase 3 of Relay Loadability: Stable Power Swings.
- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and will be improved in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPC SDT believes that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

B. Requirements and Measures

Rationale for R1:

Part 1.1 A Protection System Coordination Study (PSCS) is necessary to verify coordination of Protection Systems for existing and new ~~Interconnected~~Interconnecting Elements. The drafting team defines the term "~~Interconnected~~Interconnecting Element" as "A BES Element that electrically joins ~~facilities~~ Facilities~~owned by~~: a) owned by separate Registered Entities, or b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner)."

Part 1.1.1 The drafting team believes 60 calendar months is an appropriate period of time for entities to perform the PSCS required where no study exists. The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with ~~Interconnected~~Interconnecting Elements that warrants a shorter time frame.

Part 1.1.2 The drafting team believes that 12 calendar months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current change at an interconnecting bus, where such conditions may warrant a new PSCS, or to technically justify why no such study is required. Refer to the Application Guidelines for Requirement R1 for examples of ~~p~~Protection ~~s~~Systems where technical justifications may be used.~~, e.g., when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current.~~

Part 1.1.3 The drafting team believes that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, Part 3.1, or to technically justify why no such study is needed. The drafting team believes the timeframe associated with the requirement for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies ~~associated with Requirement R3, Part 3.1~~ is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations. ~~The drafting team believes that six months is an appropriate period of time for entities to perform the studies required or to technically justify why no such study is needed when details of changes are provided associated with Requirement R3 Part 3.3.~~

Part 1.1.4 The drafting team believes that entities must perform the studies required when notified of changes identified in Requirement R3, Part 3.3, or to technically justify why no such study is needed. The drafting team believes that six months is an appropriate period of time for entities to perform the studies required or to technically justify why no such study is needed when details of changes are provided associated with Requirement R3 Part 3.3

Part 1.2 The drafting team believes to properly ensure coordination of Protection Systems associated with ~~Interconnected~~Interconnecting Element(s), all entities need to share the summary of results of a PSCS and assess the study results. The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS performed in accordance with Requirement R1, Part 1.1 to the other owner(s) of the Protection

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation* [am1]*Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1.1. Perform a Protection System Coordination Study (PSCS) for each of its ~~Interconnected~~ Interconnecting Elements as follows:

1.1.1 Within 60 calendar months after the effective date of this standard, if no PSCS for that ~~Interconnected~~ Interconnecting Element exists.

1.1.2 Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required.

1.1.3 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or technically justify why such a study is not required.

~~1.1.3~~**1.1.4** ~~, or w~~Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3,~~;~~ or technically justify why such a study is not required.

1.2. Within 90 calendar days after the completion of each PSCS or the technical justification, provide to the other owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s), a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed), or the technical justification.

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, ~~and~~ 1.1.3, and 1.1.4 is a dated PSCS, or the summary results of each PSCS (hard copy or electronic file formats) demonstrating the time frames specified or agreed to in Parts 1.1.1, 1.1.2, ~~and~~ 1.1.3, and 1.1.4 were achieved. Acceptable evidence of a technical justification for not performing a PSCS as specified in Parts 1.1.2, ~~and~~ 1.1.3, and 1.1.4 may include, but is not limited to, documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any aspect~~s~~ of coordination.

M2. Acceptable evidence for Requirement R1, Part 1.2 is dated documentation demonstrating that the summary results of each PSCS or the technical justification (hard copy or electronic file formats) were provided within the specified time frame to the owner(s) of the Protection System(s) associated with the ~~Interconnected~~ Interconnecting Element(s).

Rationale for R2: This requires a periodic review of Fault currents at the interconnecting bus and providing the results to the applicable entities when changes occur that meet the criteria of Requirement R2. It is important that ~~interconnected~~interconnecting Facility owners are kept aware of changes that could affect proper performance of their Protection Systems. The Transmission Owner is identified as the entity responsible for performing the short circuit studies because they maintain the data necessary to perform the studies. Note: short circuit studies are used to determine the Fault current values at the interconnecting bus where a PSCS exists. These studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team believes 60 calendar months provides the entities flexibility to ~~either technically justify why Fault current does not affect the Protection System coordination, or~~ schedule and perform the activities specified in Requirement R2, Parts 2.1 and 2.2.

~~The drafting team recognizes the coordination of some types of Protection Systems is unaffected by changes in Fault current and, where technically justified, can be exempted from the short circuit review.~~

Part 2.1 The drafting team believes maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus are necessary quantities needed to review the coordination.

Part 2.2 The drafting team is including this equation to assure a consistent approach is used by each Transmission Owner when calculating the percent change in Fault current values.

Part 2.2.1 The drafting team believes the 30-calendar day time frame is reasonable for providing the Fault current information to the owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element. The drafting team determined that a change in Fault current of 10% indicates an appropriate point at which to provide this information, based on the fact that Protection Systems are typically set with margins above 10%.

R2. For each ~~Interconnected~~ Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months~~, technically justify why Fault current does not affect the Protection System coordination, or~~: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

2.1. Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at ~~the~~ its interconnecting bus(s) where a ~~Protection System Coordination Study (~~PSCS~~)~~ is available per Requirement R1.

2.2. Calculate the percent change between the Fault current values (single line to ground and 3-phase for ~~the~~ its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation:

$$\%\,Change = \left|\frac{Iscs - Ipscs}{Ipscs}\right| x\ 100$$

Where: I_{scs} = Fault current value from present short circuit study

And: I_{pscs} = Fault current value used in the most recent PSCS

2.2.1 Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (I_{scs}) to each owner of the Protection System(s) associated with the ~~Interconnected~~ Interconnecting Element(s).

~~**M3.** Acceptable evidence of technical justification for not performing a short circuit study as specified in Requirement R2, could be documented engineering analyses or assessments that demonstrate why Fault current does not impact any aspects of coordination.~~

~~M4.~~M3. Acceptable evidence for Requirement R2, Parts 2.1 and 2.2 is dated documentation (hard copy or electronic file formats) that contains the present Fault current values from the short circuit study for each interconnecting bus analyzed, and identifies the percent change from the Fault current values used in the most recent PSCS determined by the equation.

~~M5.~~M4. Acceptable evidence for Requirement R2, Part 2.2.1 is dated documentation (hard copy or electronic file formats) that the updated Fault current values (I_{scs}), were provided within the specified timeframe to each owner of the Protection System associated with the ~~Interconnected~~ Interconnecting Element.

Rationale for R3: This requires the transfer of appropriate information to the entities associated with each ~~Interconnected~~ Interconnecting Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.

Part 3.1 The reliability objective of this requirement is to enable the process of conducting PSCSs by ensuring that the information is provided to the owner(s) of the Protection Systems associated with ~~Interconnected~~Interconnecting Element(s). The drafting team believes that information about any proposed change or addition (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the ~~Interconnected~~Interconnecting Element. The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list provided in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Requirement 1, Part 1.1.

Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information in a timely manner in order to perform a PSCS, as required in Requirement 1, Parts 1.1.1, 1.1.2, ~~and~~ 1.1.3, and 1.1.4. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed-to schedule, if appropriate.

Part 3.3 The drafting team believes 30 calendar days is sufficient time to provide the information.

Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that describes the information listed in Requirement R3, Parts 3.1 and 3.3 below would be sufficient for use by all entities.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same ~~Interconnected~~ Interconnecting Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the ~~Interconnected~~ Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the ~~Interconnected~~ Interconnecting Element(s).

- New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to a transmission system Element that alter any sequence or mutual coupling impedance
- Changes to generator unit(s) that result in a change in impedance

- Changes to the generator step-up transformer(s) that result in a change in impedance

3.2. Requested information related to the coordination of Protection Systems associated with an ~~Interconnected~~ Interconnecting Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule.

3.3. Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

~~M6.~~M5. Acceptable evidence for Requirement R3, Part 3.1 may include, but is not limited to, documentation (hard copy or electronic file formats) demonstrating that a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) as identified in the bulleted list, was provided to each responsible entity connected to the same ~~Interconnected~~Interconnecting Element.

~~M7.~~M6. Acceptable evidence for Requirement R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was provided according to the agreed-upon schedule, or within 30 calendar days absent such an agreement.

~~M8.~~M7. Acceptable evidence for Requirement R3, Part 3.3 is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the permanent changes made was provided within 30 calendar days.

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with ~~Interconnected~~Interconnecting Elements ~~affirm~~ confirm that the Protection System(s) applied were reviewed and a response was provided to the other owner(s). The review assures that the owners of Protection Systems associated with the affected Interconnected Element are aware of the changes and have responded with comments if necessary.~~are acceptable per the conditions identified in Parts 4.1 and 4.2.~~

~~Part 4.1~~ The drafting team believes 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with ~~Interconnected~~Interconnecting Elements to review the summary results of a PSCS or the technical justification and respond. Note: Per Requirement R1, Part 1.2, at a minimum, the summary results of a PSCS must include the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. The response should indicate ~~acceptance with the review~~ the results~~/conclusions~~ of the PSCS or the technical justification were reviewed and, if applicable, ~~; or rejection of or disagreement with the review results/conclusions and offer of suggestions/modifications to resolve~~ any identified ~~coordination~~ issues.

Note: The drafting team recognizes there could be situations where one owner may not agree with the other owner's protection philosophy but they can ~~accept~~ confirm that there~~-proposed changes since~~ were no identified coordination issues~~ were identified~~.

~~Part 4.2 The drafting team believes that proposed changes or modifications (including project schedules) to Facilities associated with the Interconnected Element, as described in Requirement R3, Part 3.1, or modifications suggested in Requirement R4, Part 4.1 must be communicated and accepted~~ a response received ~~prior to the in-service date.~~ The

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that received a PSCS or a technical justification explaining why a PSCS is not required (per Requirement R1, Part 1.2) shall, within 90 calendar days after receipt or according to an agreed upon schedule, review the summary results or the technical justification, and respond to the other owner(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Confirming that the summary of results was reviewed and no coordination issues were identified, or
- Confirming that the summary of results was reviewed with any identified coordination issue(s) noted, or
- Confirming that a technical justification was reviewed and no issues were identified, or
- Confirming that a technical justification was reviewed with any identified issue(s) noted

~~M9.~~M8. Acceptable evidence for Requirement R4~~, Part 4.1~~ is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement.

Rationale for ~~R4~~R5: This requirement ensures owner(s) of Protection System(s) associated with ~~Interconnected~~Interconnecting Elements have communicated and resolved any identified coordination issues prior to implementing changes in~~affirm that~~ the Protection System(s) (in-service date). ~~applied are acceptable per the~~

~~R4.~~R5. After receiving a response per Requirement R4, each Transmission Owner, Generator Owner, and Distribution Provider shall resolve any identified coordination issues, prior ~~Each~~ to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element. ~~Transmission Owner, Generator Owner, and Distribution Provider shall:~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~4.1. Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a PSCS (per Requirement R1, Part 1.2) and respond to the other owner(s):~~

- ~~Accepting the resultsConfirming that the summary of results was reviewed and no coordination issues were identified, or~~
- ~~Rejecting the results and Ssuggesting modification(s) to resolve any identified coordination issue(s).~~

~~4.2. Prior to implementing any proposed change(s) or modifications addition(s) associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted received the Protection System(s) changes including the resolution of any identified coordination issues.~~

~~M10.~~M9. Acceptable evidence for Requirement R5~~4, Part 4.2~~ is dated documentation (hardcopy or electronic file formats) demonstrating that a response per Requirement R4 was received and that~~, prior to implementation of any proposed Protection System(s) changes or modifications, communications (e.g. email acknowledgements) of those changes were completedreviewed, and~~ any identified coordination issues were ~~resolved and acceptedaddressed~~resolved prior to implementation of any proposed Protection System(s) changes or additions.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System associated with an ~~Interconnected~~Interconnecting Element shall each keep data or evidence to show compliance with Requirements R1, R2, R3, and R4, and Measures M1 through M10, since the last audit, unless directed by its Compliance Enforcement[am2] Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner or Distribution Provider that owns a Protection System at a Facility associated with an ~~Interconnected~~Interconnecting Element is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.3, or technically justified why a study was not required, but was late by less	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.3, or technically justified why a study was not	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.3, or technically justified why a study was not	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required but was late by more than 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.3, or technically justified why a study was not required but was late by more

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.4, or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by less than or equal to 10 calendar days.	required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.4, or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.4, or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	than 60 calendar days OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.4, or technically justified why a study was not required but was late by more than 60 calendar days OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days. OR The responsible entity failed to perform a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, ~~or~~ 1.1.3, or 1.1.4. OR The responsible entity failed

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2, ~~or~~ 1.1.3, or 1.1.4. OR The responsible entity failed to provide Protection System Coordination Study results in accordance with Requirement R1, Part 1.2.
R2	Long-term Planning	Medium	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by less than or equal to 30 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days.	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 30 calendar days but less than or equal to 60 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 60 calendar days but less than or equal to 90 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 90 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault currents, according to the equation designated in Requirement R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.
R3	Operations Planning	Medium				The responsible entity failed to provide the owner(s) of the Facility associated with the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	~~Interconnected~~Interconnecting Element, details for any proposed change or addition identified in Requirement R3, Part 3.1. OR The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.
R4	Operations Planning	Medium	The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following the receipt of the summary results of the Protection System	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following the receipt of the summary results of the Protection System	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following the receipt of the summary results of the Protection System	The responsible entity responded in more than 120 calendar days following the receipt of the summary results of the Protection System Coordination Study or technical justification, as

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Coordination Study or technical justification, as required in Requirement R4.	Coordination Study or technical justification, as required in Requirement R4.	Coordination Study or technical justification, as required in Requirement R4.	required in Requirement R4. OR The responsible entity failed to review the summary results of the Protection System Coordination Study or the technical justification provided to them in accordance with Requirement R4. OR The responsible entity failed to respond to the other owners in accordance with Requirement R4.
~~R4~~R5	Operations Planning	Medium	~~The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.~~	~~The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.~~	~~The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.~~	~~The responsible entity responded in more than 120 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.~~ ~~OR~~ ~~The responsible entity failed to review the summary results of the Protection System Coordination Study provided to them in~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~accordance with Requirement R4, Part 4.1.~~ ~~OR~~ ~~The responsible entity failed to respond to the other owners in accordance with Requirement R4, Part 4.1.~~ ~~OR~~ The responsible entity failed to ~~affirm that the other owner(s) of each Facility associated with the affected Interconnected Element accepted the Protection System(s) changes including the~~ resolve ~~ution of~~ any identified coordination issues, prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element ~~implementation of those changes~~, as required in Requirement ~~R4, Part 4.2~~5.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Purpose:

To coordinate Protection Systems for ~~Interconnected~~Interconnecting Elements, such that Protection System components operate in the ~~desired~~ intended sequence during Faults.

This standard requires that separate Registered Entities communicate with each other to coordinate Protection System components on existing ~~Interconnected~~Interconnecting Elements; and communicate with each other prior to the energization of new or modified Protection Systems associated with ~~Interconnected~~Interconnecting Elements. The goal of the coordination is to verify that the Protection Systems intended for sensing Faults will operate in the ~~desired~~ intended sequence for internal and external Faults on the ~~Interconnected~~Interconnecting Element.

Requirement R1:

This requirement directs the applicable entities to perform a Protection System Coordination Study (PSCS) for every ~~Interconnected~~Interconnecting Element to verify coordination of existing Protection Systems where no recent study exists; or when Facility configuration changes are made, or where Fault current changes of 10% or more have occurred. In developing the language to define a PSCS, the System Protection Coordination Standard Drafting Team (SPC SDT) considered various reference books discussing protective relaying theory and application, along with the following description of "coordination of protection" from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Using the reference material cited above as guidance, the drafting team defined the term Protection System Coordination Study (PSCS) for use within the PRC-027-1 Reliability Standard as:

> "A study that documents~~emonstrates~~ existing or proposed Protection Systems operate in the ~~desired~~ intended sequence for clearing Faults."

PSCSs comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in PSCSs include maximum generation with the transmission system under normal operating conditions and under single contingency conditions. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

Part 1.1.1:

The drafting team believes applicable entities should have a documented PSCS for each ~~Interconnected~~Interconnecting Element to validate the Protection Systems associated with those ~~Interconnected~~Interconnecting Elements perform in a manner consistent with the purpose of this Standard. Additionally, the drafting team believes that 60 calendar months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with ~~Interconnected~~Interconnecting Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

Parts 1.1.2~~ and 1.1.3 further direct that PSCSs must be completed under the following two circumstances~~:

After notification of an identified 10% or greater change in Fault current (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1), the notified entities must perform a new PSCS of the ~~Interconnected~~Interconnecting Element or document why a study is not required. The drafting team recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater change in Fault current may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the 12-calendar month time frame associated with this requirement represents a reasonable period to perform the studies that are required after identification by the 60-calendar month Fault current review.

~~1.~~ Part 1.1.3:

After proposing or being notified of a change at a Facility associated with the ~~Interconnected~~Interconnecting Element, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the proposed or notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the timeframe associated with performing a PSCS for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3, Part 3.1 is unnecessary because notification of such a change may occur weeks or years prior to the change due to the wide variety of conditions that may be associated with a particular change. The drafting team sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R5~~4, Part 4.2.~~ .

Part 1.1.4:

After being notified of a change at a Facility associated with the Interconnecting Element associated with Requirement R3, Part 3.3, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes that six calendar months is an appropriate period of time for entities to perform the studies required, or to technically justify why no such study is needed~~, when details of changes are provided associated with Requirement R3 Part 3.3~~.

Examples of Protection Systems where technical justifications may be used include:

1. Differential elements
2. Distance elements where infeed is not used in determining reach for the protection scheme.
3. Supervised overcurrent elements enabled by:
    - Loss of potential condition
    - Some communication assisted tripping
    - Switch-Onto-Fault (SOTF)
4. Reverse power, definite time &/or time overcurrent elements:
    - Designed to coordinate during maximum generation with the transmission system under normal operating conditions and under single contingency conditions regardless of Fault current.
    - Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.).

~~2.~~

Requirement R1, Part 1.2 directs the entity performing the PSCS to provide a summary of the study results or a technical justification to the affected ~~Interconnected~~Interconnecting Element owner(s). - The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS it performed to the other owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s). (Note: In cases where a single group performs an overall coordination study for a given ~~Interconnected~~Interconnecting Element; a single document that meets the requirements for a summary of the results of the PSCS would be sufficient for use by both Registered Entities.) ~~As guidance, t~~The ~~drafting team lists the~~ following inputs and results of a PSCS ~~that may~~ must be included in the summary provided pursuant to this requirement:

1. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Facility, and which were reviewed for coordination of protective relays as part of the study, including the contingencies used in the evaluation.
2. A listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study.
3. A listing of any issues associated with the relay settings of the other owner(s) at the Facility that were identified by the study.
4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The drafting team investigated various inputs that would trigger a review of the existing PSCSs and determined, through the experience of the drafting team members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated PSCS may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates the Transmission Owner ~~either provide a technical justification stating why Fault current does not affect the Protection System coordination of a specific Interconnected Element or~~ perform a periodic review of Fault currents.

~~**Examples of Protection Systems where technical justifications may be used include:**~~

1. ~~Differential elements~~
2. ~~Distance elements where infeed is not used in determining reach for the protection scheme.~~
3. ~~Supervised overcurrent elements enabled by:~~
   - ~~Loss of potential condition~~
   - ~~Some communication assisted tripping~~
   - ~~Switch-Onto-Fault (SOTF)~~
4. ~~Reverse power, definite time &/or time overcurrent elements:~~
   - ~~Designed to coordinate during maximum generation with the transmission system under normal operating conditions and under single contingency conditions regardless of Fault current.~~
   - ~~Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate~~

~~for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.).~~

The short circuit study provides the Fault current values used to calculate the percent change between the most recent PSCS and the present Fault current values indicated by the short circuit study performed pursuant to Requirement R2, Part 2.1. This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.2. Short circuit studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team believes that 60 calendar months is an appropriate interval for ~~technically justifying why Fault currents do not affect the Protection System coordination of a specific Interconnected Element, or for~~ reviewing Fault currents. The drafting team believes studies associated with changes that would affect the coordination in less than 60 calendar months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.2.1 further directs the Transmission Owner to, within 30 calendar days, inform each owner of the Facility associated with the ~~Interconnected~~Interconnecting Element when short circuit studies indicate that 10% changes in Fault current have occurred at the interconnecting bus(s). The drafting team believes the 30-calendar day time frame associated with this requirement is reasonable for providing the Fault current information to the ~~interconnected~~interconnecting entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the functional entity responsible for performing the short circuit studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.

Requirement R3:

This directs the registered functional entity initiating any proposed change or addition to provide the details to the other affected entities of the ~~Interconnected~~Interconnecting Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes. Documentation provided to these other owners may include, but is not limited to, power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings. The recipient will incorporate the applicable information into its PSCSs to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. The drafting team recognizes that Facility changes at other locations can impact the PSCS of the Facility associated with the ~~Interconnected~~Interconnecting Element; e.g., the addition of a large autotransformer bank or generator not directly connected to the ~~Interconnected~~Interconnecting Element. The drafting team believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the drafting team sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a PSCS or, absent such agreement, within 30 calendar days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

Requirement R3, Part 3.3 ~~Additionally, this requirement~~ includes a provision for providing details associated with changes to the previously agreed-upon coordination when permanent changes are made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the drafting team believes 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

Requirement R4:

~~The reliability objective of this requirement is to bring the process of Protection System coordination full circle by gaining the confirmation of interconnected entities that their Protection Systems are coordinated consistent with the purpose of this standard. Cooperative participation of Facility owners in communicating Protection System(s) design, and study results will achieve coordination of Protection Systems for reliable operation of the BES during Faults.~~

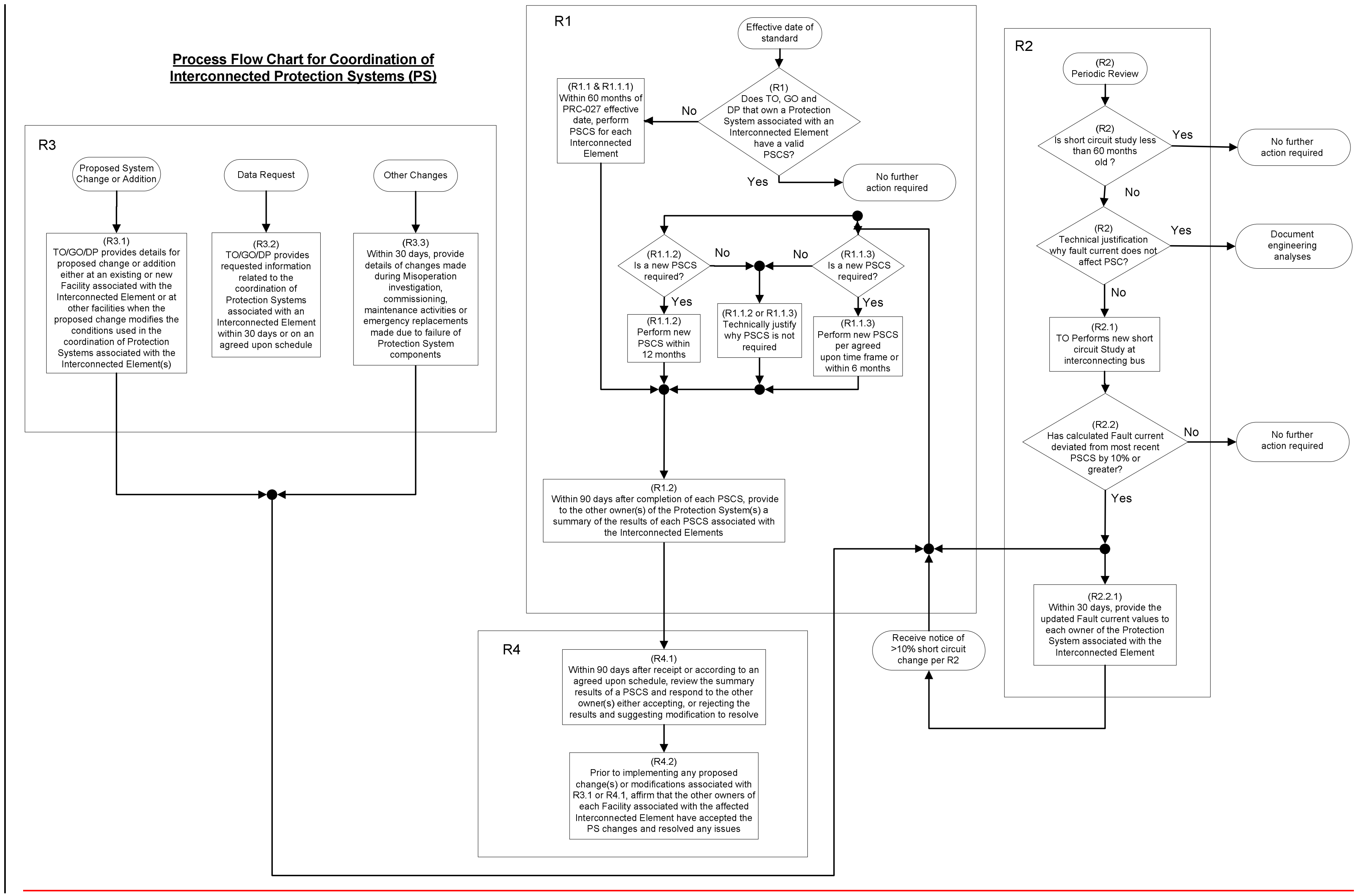
Requirement R4~~, Part 4.1~~ directs applicable entities, within 90 calendar days after receipt, to review the summary results of a PSCS or the technical justification, as described in Requirement R1, Part 1.2; and respond that they have reviewed and identified any issues. ~~as to whether they accepting or rejecting the results, and if rejecting, suggesting modifications to resolve any identified coordination issues.~~ The drafting team believes 90 calendar days after receipt ~~of the results of a PSCS~~ provides a reasonable time for the owners of Facilities to review ~~the summary results of a PSCS.~~

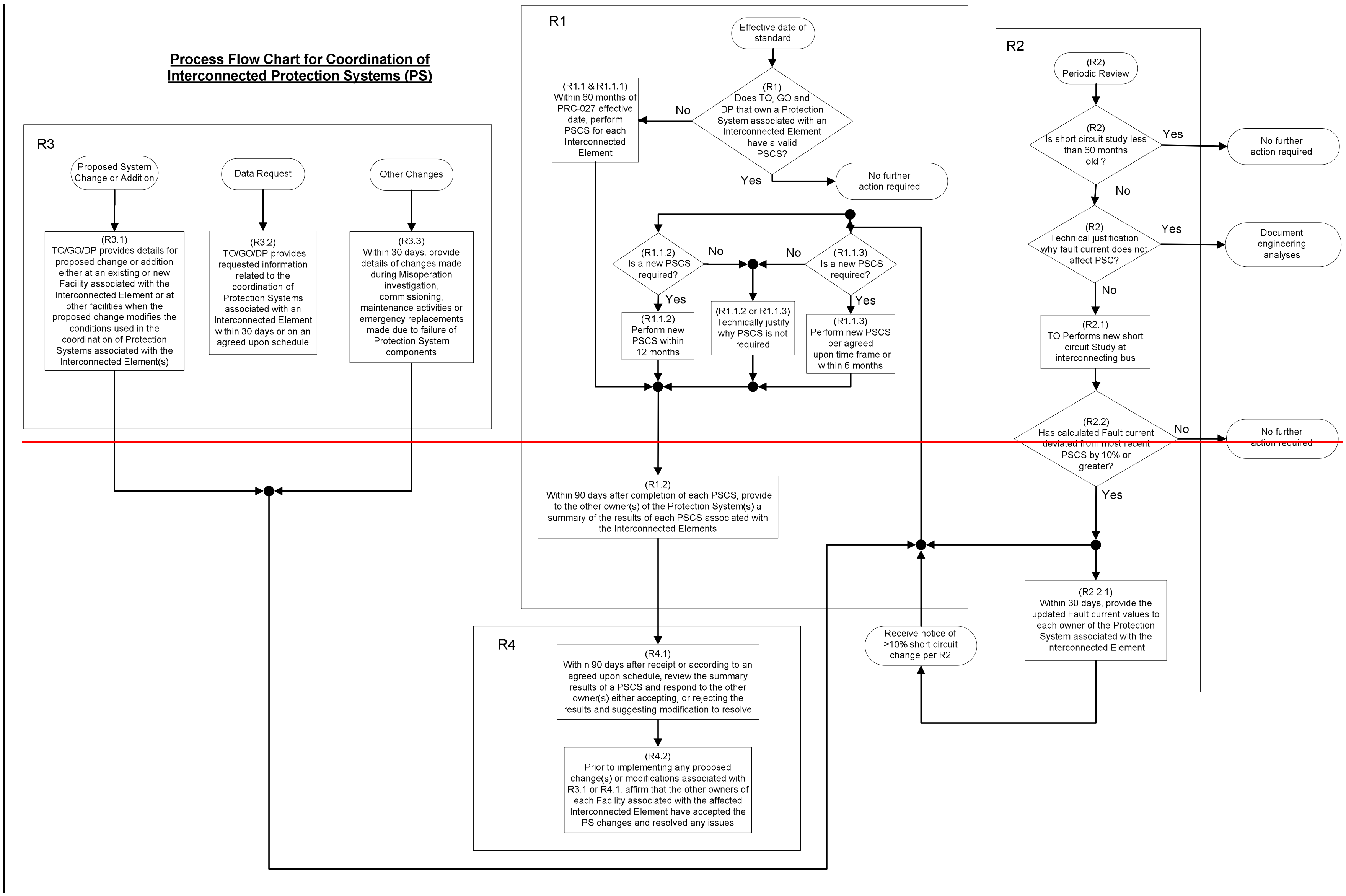
~~Requirement R4, Part 4.2 directs entities to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes as described in Requirement 3, Part 3.1 and Requirement 4, Part 4.1 prior to the in-service date of those changes. Any coordination issues identified during the review must be resolved prior to implementing the proposed changes. The purpose of Requirement 4, Part 4.2 is to assure the effects the proposed changes have on Protection Systems at a Facility associated with the Interconnected Element have been considered by all affected entities.~~

Requirement R5:

The reliability objective of this requirement is to bring the process of Protection System coordination full circle by ensuring owners of Protection System(s) associated with Interconnecting Elements have communicated and resolved any identified coordination issues prior to implementing changes in the Protection System(s) (in-service date).

Process Flow Chart: Below is a complete representation of the process, including the relationships between requirements:
Note: All timeframes referenced in the diagram below represent "calendar month" or "calendar day" timeframes.


Process Flow Chart for Coordination of Interconnected Protection Systems (PS)
R3
Proposed System Change or Addition
Data Request
Other Changes
(R3.1) TO/GO/DP provides details for proposed change or addition either at an existing or new Facility associated with the Interconnected Element or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)
(R3.2) TO/GO/DP provides requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 days or on an agreed upon schedule
(R3.3) Within 30 days, provide details of changes made during Misoperation investigation, commissioning, maintenance activities or emergency replacements made due to failure of Protection System components
R1
Effective date of standard
(R1) Does TO, GO and DP that own a Protection System associated with an Interconnected Element have a valid PSCS?
No
Yes
(R1.1 & R1.1.1) Within 60 months of PRC-027 effective date, perform PSCS for each Interconnected Element
No further action required
(R1.1.2) Is a new PSCS required?
No
No
(R1.1.3) Is a new PSCS required?
Yes
Yes
(R1.1.2) Perform new PSCS within 12 months
(R1.1.2 or R1.1.3) Technically justify why PSCS is not required
(R1.1.3) Perform new PSCS per agreed upon time frame or within 6 months
(R1.2) Within 90 days after completion of each PSCS, provide to the other owner(s) of the Protection System(s) a summary of the results of each PSCS associated with the Interconnected Elements
R2
(R2) Periodic Review
(R2) Is short circuit study less than 60 months old ?
Yes
No further action required
No
(R2) Technical justification why fault current does not affect PSC?
Yes
Document engineering analyses
No
(R2.1) TO Performs new short circuit Study at interconnecting bus
(R2.2) Has calculated Fault current deviated from most recent PSCS by 10% or greater?
No
No further action required
Yes
(R2.2.1) Within 30 days, provide the updated Fault current values to each owner of the Protection System associated with the Interconnected Element
Receive notice of >10% short circuit change per R2
R4
(R4.1) Within 90 days after receipt or according to an agreed upon schedule, review the summary results of a PSCS and respond to the other owner(s) either accepting, or rejecting the results and suggesting modification to resolve
(R4.2) Prior to implementing any proposed change(s) or modifications associated with R3.1 or R4.1, affirm that the other owners of each Facility associated with the affected Interconnected Element have accepted the PS changes and resolved any issues


Process Flow Chart for Coordination of Interconnected Protection Systems (PS)
R3
Proposed System Change or Addition
Data Request
Other Changes
(R3.1) TO/GO/DP provides details for proposed change or addition either at an existing or new Facility associated with the Interconnected Element or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)
(R3.2) TO/GO/DP provides requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 days or on an agreed upon schedule
(R3.3) Within 30 days, provide details of changes made during Misoperation investigation, commissioning, maintenance activities or emergency replacements made due to failure of Protection System components
R1
Effective date of standard
(R1) Does TO, GO and DP that own a Protection System associated with an Interconnected Element have a valid PSCS?
No
Yes
(R1.1 & R1.1.1) Within 60 months of PRC-027 effective date, perform PSCS for each Interconnected Element
No further action required
(R1.1.2) Is a new PSCS required?
(R1.1.3) Is a new PSCS required?
No
No
Yes
Yes
(R1.1.2) Perform new PSCS within 12 months
(R1.1.2 or R1.1.3) Technically justify why PSCS is not required
(R1.1.3) Perform new PSCS per agreed upon time frame or within 6 months
(R1.2) Within 90 days after completion of each PSCS, provide to the other owner(s) of the Protection System(s) a summary of the results of each PSCS associated with the Interconnected Elements
R2
(R2) Periodic Review
(R2) Is short circuit study less than 60 months old ?
Yes
No further action required
No
(R2) Technical justification why fault current does not affect PSC?
Yes
Document engineering analyses
No
(R2.1) TO Performs new short circuit Study at interconnecting bus
(R2.2) Has calculated Fault current deviated from most recent PSCS by 10% or greater?
No
No further action required
Yes
(R2.2.1) Within 30 days, provide the updated Fault current values to each owner of the Protection System associated with the Interconnected Element
Receive notice of >10% short circuit change per R2
R4
(R4.1) Within 90 days after receipt or according to an agreed upon schedule, review the summary results of a PSCS and respond to the other owner(s) either accepting, or rejecting the results and suggesting modification to resolve
(R4.2) Prior to implementing any proposed change(s) or modifications associated with R3.1 or R4.1, affirm that the other owners of each Facility associated with the affected Interconnected Element have accepted the PS changes and resolved any issues

Example Process

An example of the interaction between entities required to gather the information to perform an accurate study is provided below. This example is given as general guidance only and is not intended to represent all situations that may occur. More detailed examples are provided along with Figures 1-5 in the section that follows this example.

- The initiating entity (Entity A) will contact the ~~interconnected~~interconnecting entity (Entity B) and provide details of the ~~proposed~~ change(s) and may also request up-to-date Protection System information.
- Entities A and B will determine whether a new PSCS is required. In this example both agree that a new study is required. The study may be a joint study, individual studies, or a single study provided by Entity A and reviewed and approved by Entity B. In this example, the latter will occur.
- Upon receipt of the above request for information, Entity B will provide the information within 30 calendar days, or an agreed upon time frame.
- Entity A will perform a PSCS using the information received.
- Entity A will provide a summary of the results of the study to Entity B within 90 calendar days of completing the PSCS.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, respond as to whether any coordination issues were identified, and if any further action is required.
    - In cases where the study reveals that changes to Protection Systems are needed, Entity B would propose to Entity A revisions that achieve acceptable results.
    - Ultimately, both entities will collaborate in developing a mutually acceptable solution.

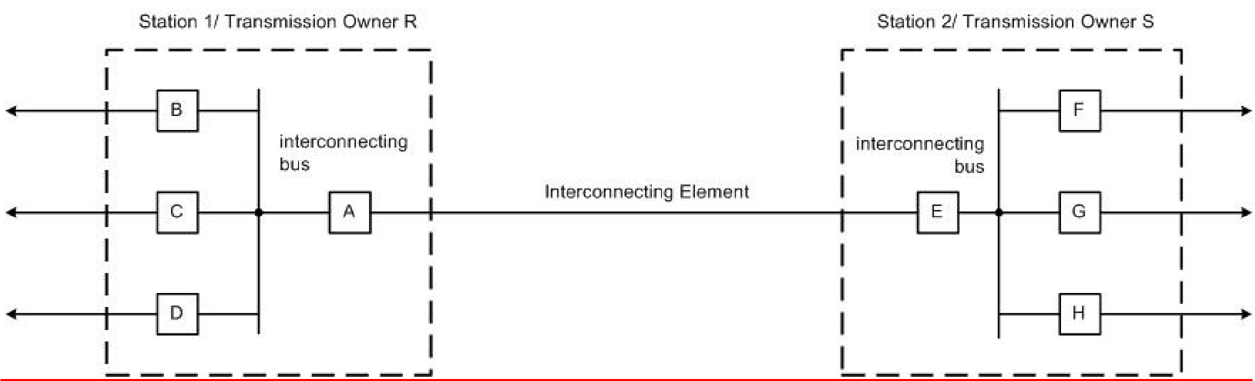
Diagrams

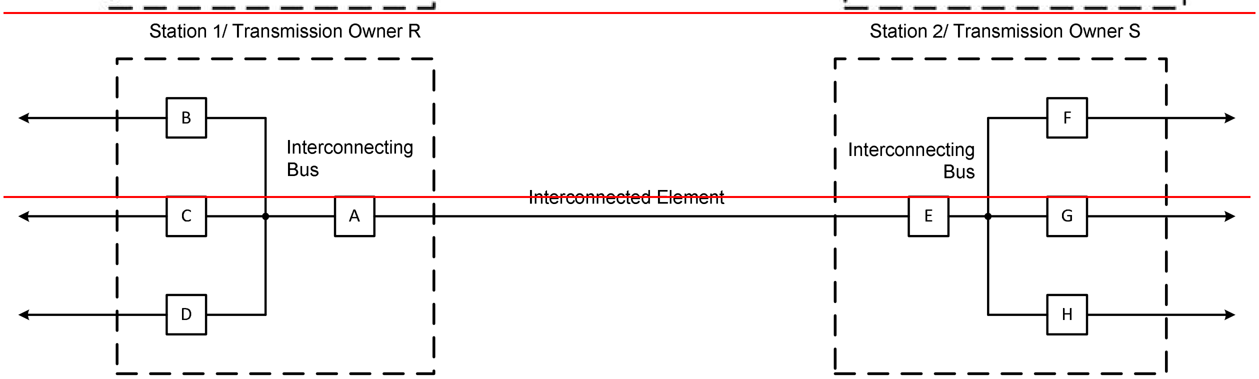
Introduction: The diagrams below are intended to provide guidance, to the owners of Facilities associated with the affected ~~Interconnected~~Interconnecting Element, for meeting the requirements of this standard. These examples are not intended to be inclusive of all situations and are based on the assumption that entities employ the appropriate engineering expertise and due diligence in developing settings for their Protection Systems. The examples given also assume a single owner as the initiator of a Protection System Coordination Study (PSCS) for the applicable ~~Interconnected~~Interconnecting Element. In actuality, any owner or owners may initiate the process. After the reviews of the PSCS or a summary of results, and prior to implementation of changes, the owners must work together to resolve any coordination issues identified during those reviews.

NOTES:

1. Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.
2. Protection Systems of the Transmission Owners, Generator Owners, and Distribution Providers described in the Figures and examples below do not include any systems or components enumerated in the 'Background Section' of this standard under "Other Aspects of Coordination of Protection Systems Addressed by Other Projects".
3. ~~2.~~In the Figures below, the locations of the interconnecting bus(s) referenced in Requirement 2 are indicated.

Figure 1

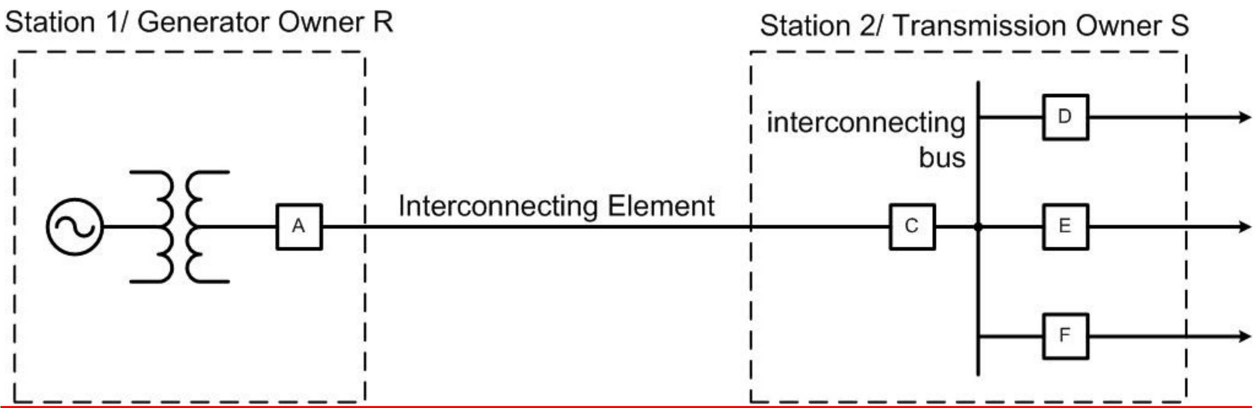


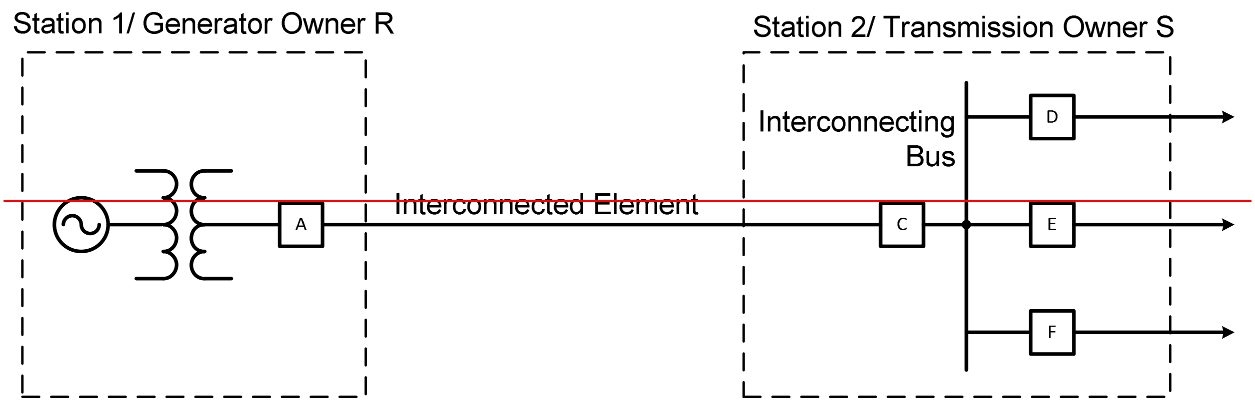


In Figure 1 above, the ~~Interconnected~~Interconnecting Element between the Transmission Owners is the transmission line between Breakers A and E.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 1, Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers E, F, G, and H. Likewise, Owner S is to develop ~~proposed~~ Protection System settings associated with Breaker E. Owner R is to review the Protection System settings associated with Breaker E (provided by Owner S) for coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

Figure 2



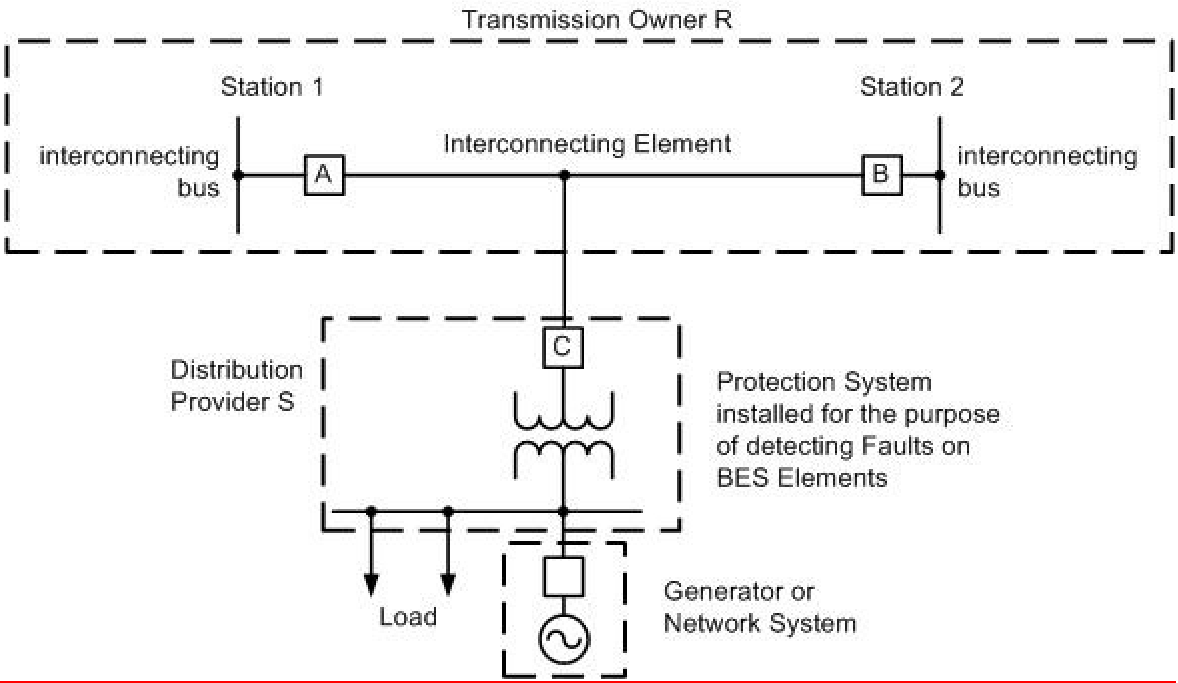


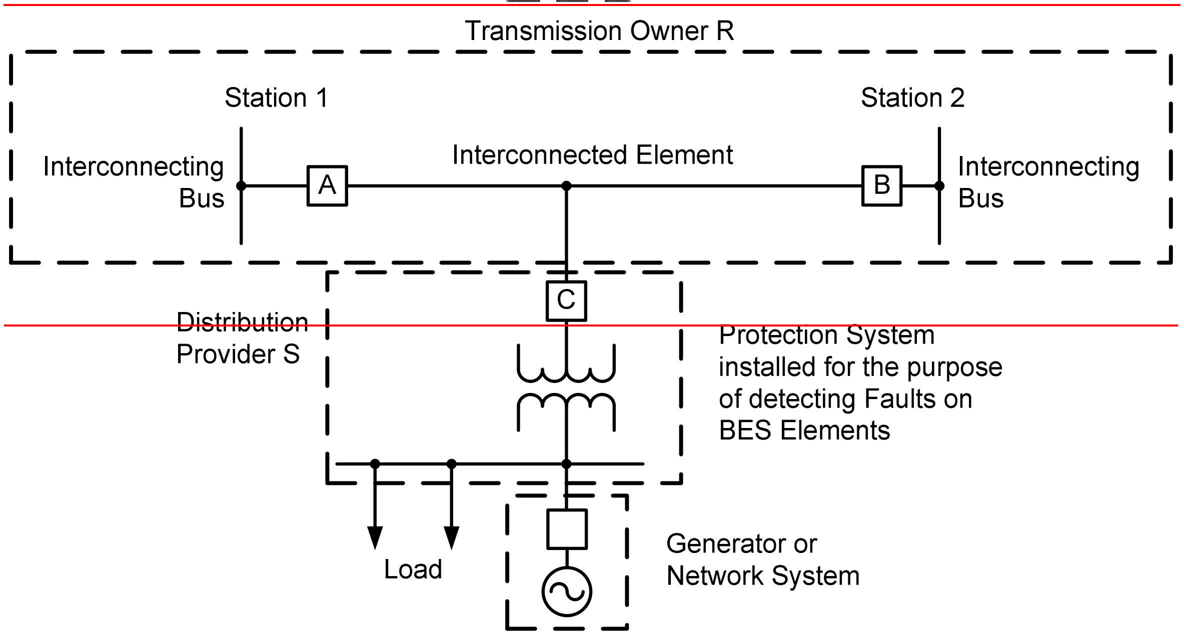
In Figure 2 above, the ~~Interconnected~~Interconnecting Element between the Transmission Owner and the Generator Owner is the transmission line or bus between Breakers A and C.

Note: Depending on the actual configuration and/or ownership, Breaker A may, or may not, exist as a GSU unit high-side breaker or a line breaker.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 2, Owner R is to develop ~~proposed~~ Protection System settings associated with Breaker A. Transmission Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, Owner S is to develop ~~proposed~~ Protection System settings associated with Breaker C. Generator~~ion~~ Owner R is to review the Protection System settings associated with Breaker C (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3





In Figure 3 above, the ~~Interconnected~~Interconnecting Element between[am3] the Transmission Owner and the Distribution Provider is the transmission line (or tap) between the Distribution Provider's Breaker C and the point of connection to the line between the Transmission Owner's Breakers A and B.[p4] Therefore, the applicable Protection Systems per this standard are those at Breakers A, B and C.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 3, Distribution Provider S is to develop ~~proposed~~ Protection System settings associated with Breaker C. Transmission Owner R is to review the Protection System settings associated with

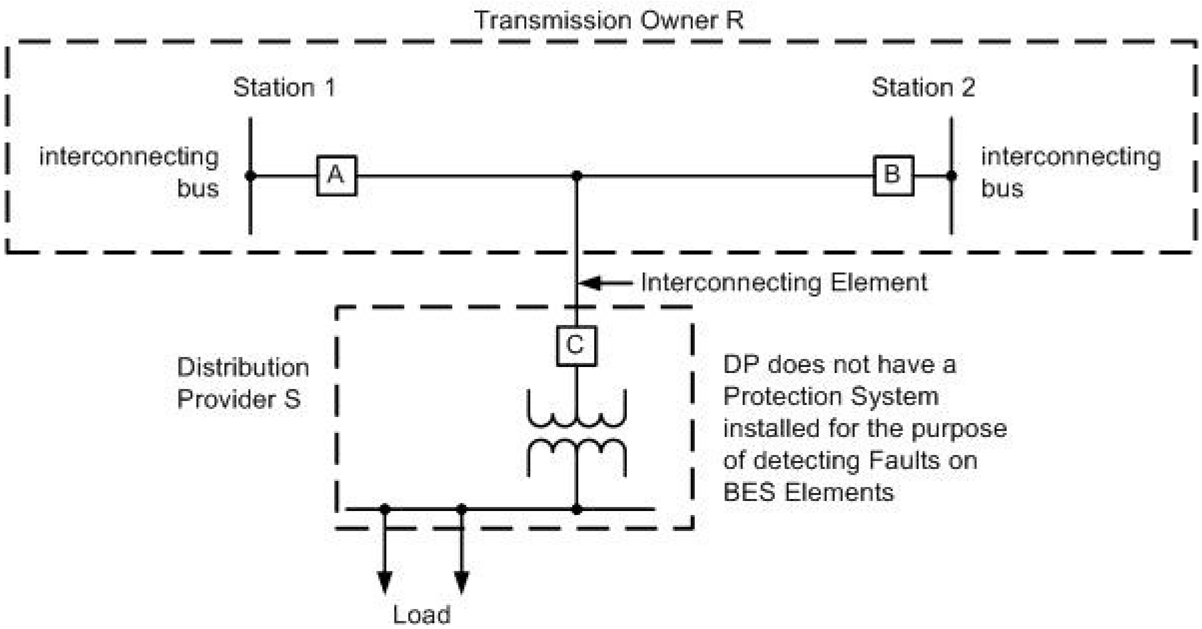
Line Breaker C (provided by Distribution Provider S) for coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2.

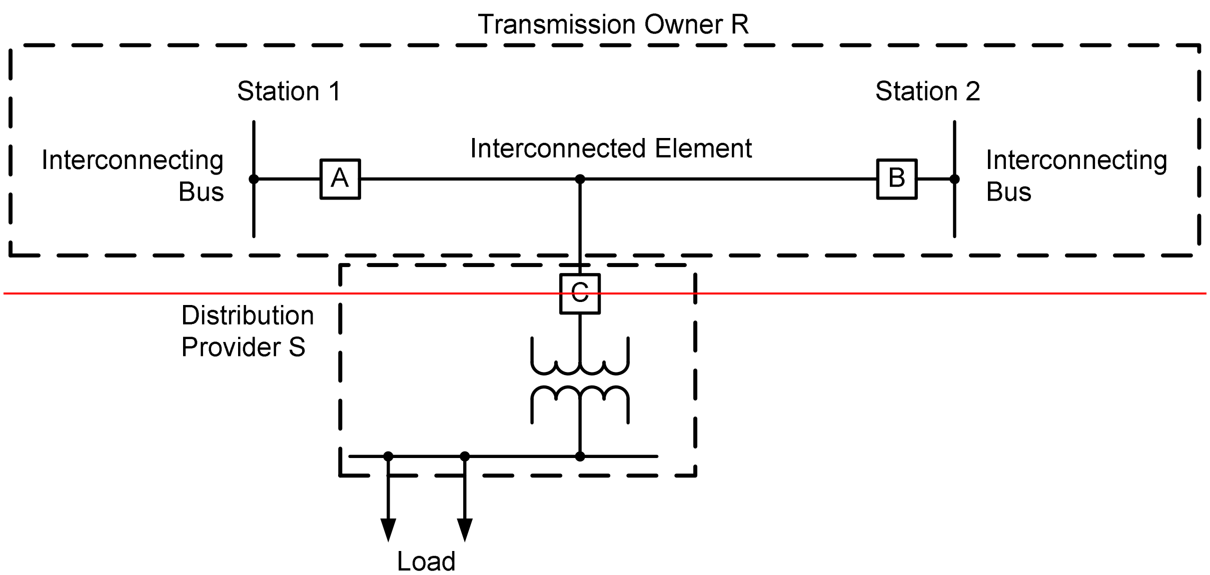
Notes:

A PSCS is required per this standard for this example if a Protection System at the Distribution Provider's substation is installed for the purpose of detecting Faults on BES Elements.

Protection Systems installed for the purpose of detecting Faults on BES Elements do not include relays that, though they may operate for such Faults, are not installed specifically for that purpose. As an example, reverse power relays are often installed to detect situations where the transmission source for a power transformer becomes de-energized (for whatever reason) while the distribution bank remains energized from a source on the low-voltage side. In this case, the settings of the reverse power relay are typically calculated based on the charging current of the transformer from the low-voltage side. Although relays installed and set in this manner may operate as a result of a Fault on a BES Element, they are not specifically installed for the purpose of detecting that Fault.

Figure 4





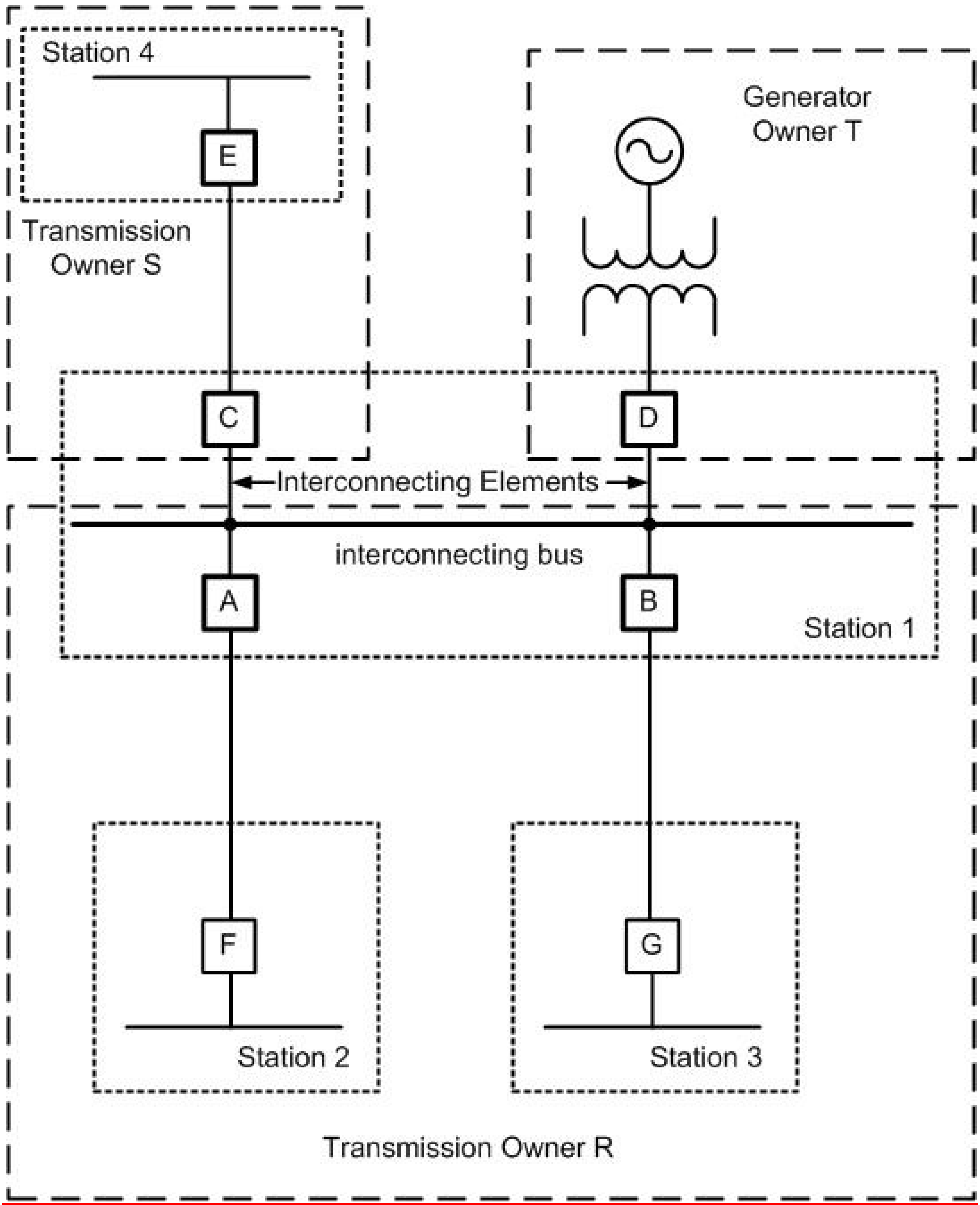
~~In Figure 4 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line or tap between the line and Breaker C.~~ The configuration above is an example excluded from this standard because the Distribution Provider S does not own Protection Systems installed for the purpose of detecting Faults on BES Elements.

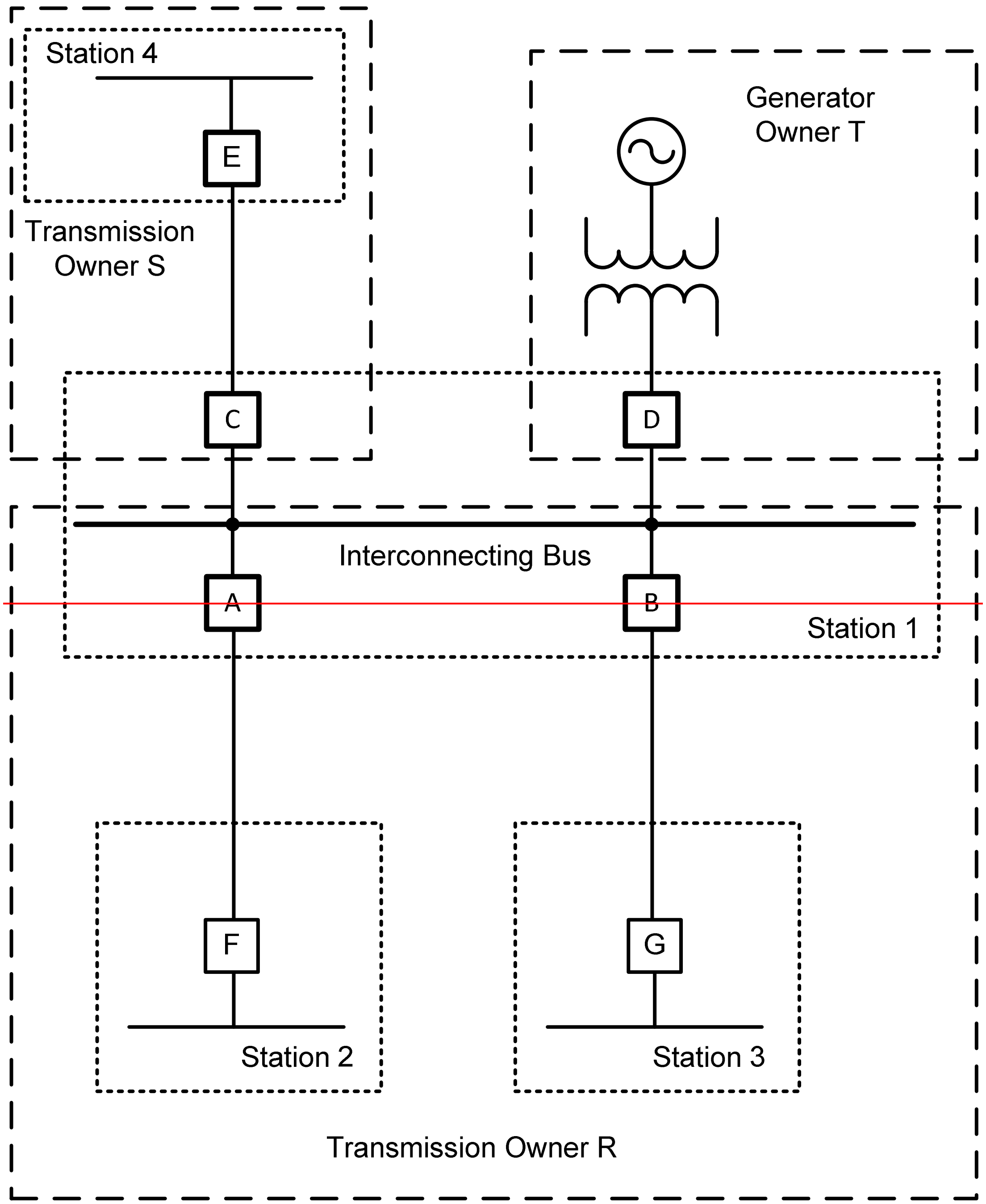
~~**Note:** No specific PSCS is required per this standard for this example since the Protection System at the Distribution Provider's substation is not installed for the purpose of detecting Faults on BES Elements.~~

Figure 5

Transmission/Generation Facility with Multiple Owners

Note: In a large majority of cases, Figure 2 would be applicable for most generator interconnections. In Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T.


Station 4
E
Transmission Owner S
Generator Owner T
C
D
Interconnecting Elements
interconnecting bus
A
B
Station 1
F
G
Station 2
Station 3
Transmission Owner R



~~In~~ Figure 5 above illustrates~~,~~ the ~~Interconnected~~Interconnecting Elements between the Transmission Owners R and S and Generator Owner T ~~is the common Transmission bus~~. In this example, Transmission Owner S and Generator Owner T are not directly ~~interconnected~~interconnecting to each other at Station 1. All direct interconnections are between Owner R and each of the other Owners connected to the common bus at Station 1.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 5:

Owner S is to develop ~~proposed~~ Protection System settings associated with Breakers C and E.

Owner T is to develop ~~proposed~~ Protection System settings associated with Breaker D, the generator, and its associated equipment.

Owner R is to develop ~~proposed~~ Protection System settings associated with Breakers A, B, F and G.

Owner R is to review the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S and/or T) for coordination issues with the Protection System settings associated with Breakers A and B.

Owner S is to review the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R and/or T) for coordination issues with the Protection System settings associated with Breaker C. To perform this review, it will be necessary that Transmission Owner R provide Owner S with its settings for Breakers A, F, B, and G, as well as the settings for Breaker D and generator Protection System settings provided to Owner R by Generator Owner T.

Owner T is to review the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R and/or S) for coordination issues with the Protection System settings associated with Breaker D or the generator Protection System. In order to perform this review, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

Consideration of Comments

Project 2007-06 System Protection Coordination
PRC-027-1

The Project 2007-06 Drafting Team thanks all commenters who submitted comments on the PRC-027-1 standard for System Protection Coordination. The standard was posted for a 30-day formal comment period from June 4, 2013 through July 3, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 67 sets of responses, including comments from approximately 196 different people from approximately 130 companies representing all 10 of the 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]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Summary Consideration of all Comments Received

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

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

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Frank Gaffney	Florida Municipal Power	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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Matt Goldberg	ISONE	NPCC	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. Lori Spence	MISO	MRO	2
4. Charles Yeung	SPP	SPP	2
5. Matt Morais	ERCOT	ERCOT	2
6. Ali Mehremadi	CAISO	WECC	2

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

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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	David Thorne	Pepco Holdings	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Carl Kinsley	Delmarva Power & Light Co.	RFC	1, 3

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

2. Alvin Depew	Pepco Holdings Inc.	RFC	1, 3

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

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Larry Raczkowski	FirstEnergy Corp	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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Morgan Senkal	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Dean Bender	BPA Transmission SPC Technical Services	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Randi Heise	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Michael Crowley	Electric Transmission	SERC	1, 3
2. Jeff Bailey	Nuclear	SERC	5
3. Chip Humphrey	Fossil & Hydro	RFC	5
4. Sean Iseminger	Fossil & Hydro	SERC	5
5. Connie Lowe	Dominion	SERC	1, 3, 5, 6
6. Mike Garton	Dominion	NPCC	1, 3, 5, 6
7. Louis Slade	Dominion	RFC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Kathi Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	DTE Electric	RFC	3, 4, 5
2. Dan Herring	DTE Electric	RFC	3, 4, 5
3. Al Eizans	DTE Electric	RFC	3, 4, 5

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

4. Dave Szulczewski	DTE Electric	RFC	3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Patrick Brown	Essential Power, LLC					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Allen Schriver	NexrEra		5
2.	Steve Berger	PPL Susquehanna, LLC		5
3.	Joe Crispino	PSEG Fossil, LLC		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.	Dana Showalter	E.ON		5
12.	William Shultz	Southern Company		5
13.	Mark Young	Tenaska, Inc		5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	John Allen	Rochester Gas & Electric	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Raymond Kinney	New York State Electric & Gas	NPCC	1
2.	Joseph Turano	Central Maine Power	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Joseph DePoorter	Madison Gas and Electric Company	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.			NA - Not Applicable	
3.	Dan Inman	MPC	MRO	1, 3, 5, 6
4.	Dave Rudolph	BEPC	MRO	3, 5, 6
5.	Kayleigh Wilkerson	LES	MRO	1, 3, 5, 6
6.	Jodi Jenson	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

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

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	3, 5, 6
16. Tom Breene	WPS	MRO	3, 4, 5, 6
17. Tony Eddleman	NPPD	MRO	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	David Dockery	Associated Electric Cooperative, Inc.	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Central Electric Power Cooperative		SERC	1, 3
2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Robert Rhodes	Southwest Power Pool		X								

Additional Member	Additional Organization	Region	Segment Selection
1. John Allen	City Utilities of Springifeld	SPP	1, 4
2. Joe Border	Board of Public Utilities, City of McPherson, KS	SPP	NA
3. Greg Froehling	Rayburn Country Electric Cooperative	SPP	3
4. Louis Guidry	Cleco Power	SPP	1, 3, 5
5. Greg Hill	Nebraska Public Power District	MRO	1, 3, 5
6. Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
7. Kyle McMenamin	Xcel Energy	SPP	1, 3, 5, 6
8. James Nail	City of Independence, Power & Light Department	SPP	3
9. Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
10. Sean Simpson	Board of Public Utilities, City of McPherson, KS	SPP	NA

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15. Group	Mary Jo Cooper	Cooper Compliance Corp	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Ken Dize	Salmon River Electric Coop	WECC	1, 3

2.	Colin Murphey	City of Ukiah	WECC	3						
3.	Angela Kimmey	Pasadena Water and Power	WECC	1, 3						
4.	Cynthia Whitchurch	Alameda Municipal Power	WECC	3						
5.	Blaine Ladd	California Pacific Electric Company	WECC	3						
6.	Elizabeth Kirkley	City of Lodi	WECC	3						

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
16. Group	Brent Ingebrigtson	LG&E and KU Services	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Affiliates	RFC	5
3.			WECC	5
4.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
5.			NPCC	6
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	David Greene	SERC RRO										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren		
2.	Bridget Coffman	Santee Cooper		
3.	Steve Edwards	Dominion, Va. Power		
4.	Phil Winston	Southern Company Services		
5.	Greg Davis	GTC		
6.	Russ Evans	SCE&G		
7.	David Greene	SERC RRO		

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	John Babik		FRCC	3
3.	Garry Baker		FRCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Group	Chang Choi	City of Tacoma	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Travis Metcalfe	Tacoma Public Utilities	WECC	3
2.	Keith Morisette	Tacoma Public Utilities	WECC	4
3.	Chris Mattson	Tacoma Power	WECC	5
4.	Michael Hill	Tacoma Public Utilities	WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
22.	Individual	Bob Steiger	Electric Reliabilty Compliance	X		X		X	X	X			
23.	Individual	Stephanie Monzon	PJM Interconnection		X								
24.	Individual	Erika Doot	Bureau of Reclamation	X				X				X	
25.	Individual	Pamela Hunter	Southern Company	X		X		X	X				
26.	Individual	Rowell Crisostomo	ATCO Electric	X									
27.	Individual	Dan Roethemeyer	Dynegy					X					
28.	Individual	John Falsey	Invenergy LLC					X					
29.	Individual	John Bee	Exelon and its Affiliates	X		X		X					
30.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	NICOLE BUCKMAN	ATLANTIC CITY ELECTRIC COMPANY			X							
33.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
34.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
35.	Individual	Mark Yerger	Potomac Electric Power Company			X							
36.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
37.	Individual	Don Jones	Texas Reliability Entity										X
38.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
39.	Individual	Michael Moltane	ITC	X									
40.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
41.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
42.	Individual	Jonathan Meyer	Idaho Power Co.	X									
43.	Individual	Bill Middaugh	Tri-State G &T	X									
44.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
45.	Individual	Karen Webb	City of Tallahassee - Electric Utility					X					
46.	Individual	Bill Fowler	City of Tallahassee			X							
47.	Individual	Scott Langston	City of Tallahassee	X									
48.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
49.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
50.	Individual	Richard Vine	California ISO		X								
51.	Individual	David Jendras	Ameren	X		X		X	X				
52.	Individual	RoLynda	Shumpert	X		X		X	X				
53.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
54.	Individual	Jack Stamper	Clark Public Utilities	X									
55.	Individual	Joe Tarantino	SMUD	X		X	X	X	X				
56.	Individual	Mike Hirst	Cogentrix Energy Power Management, LLC					X					
57.	Individual	Jim Howard	Lakeland Electric	X		X		X	X				
58.	Individual	Brian J Murphy	NextEra Energy	X		X		X	X				
59.	Individual	Larry Watt	Lakeland Electric	X		X		X	X				
60.	Individual	Anthony Jablonski	ReliabilityFirst										X
61.	Individual	John Allen	City Utilities of Springfield, Missouri	X			X						
62.	Individual	Daniela Hammons	CenterPoint Energy	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
63.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
64.	Individual	Mary Downey	City of Redding			X	X	X			X		
65.	Individual	Tony Kroskey	Brazos Electric Power Cooperative	X									
66.	Individual	Bob Thomas and Kevin Wagner	Illinois Municipal Electric Agency				X						
67.	Individual	Bret Galbraith	Seminole Electric Cooperative Inc.			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"
Brazos Electric Power Cooperative	ACES Power Marketing
Invenergy LLC	Essential Power, LLC
City of Tallahassee - Electric Utility	Florida Municipal Power Agency (FMPA)
City of Tallahassee	FMPA
Lakeland Electric	FMPA (agree with their comments)
Lakeland Electric	Lakeland Electric concurs with FMPA comments.
Cogentrix Energy Power Management, LLC	North American Generator Forum (NAGF) Standard Review Team (SRT)
Rochester Gas & Electric	NPCC
Potomac Electric Power Company	Pepco Holdings Inc, and Affiliates
ATLANTIC CITY ELECTRIC COMPANY	Pepco Holdings Inc. and Affiliates

Organization	Supporting Comments of “Entity Name”
Delmarva Power & Light Company	Ppeco Holdings Inc. and Affiliates
Shumpert	SERC PCS
Tennessee Valley Authority	SERC Protection & Control Subcommittee(PCS)
City of Redding	SMUD
City Utilities of Springfield, Missouri	Southwest Power Pool Standards Review Group

1. **Based on stakeholder comments, the drafting team modified the Purpose of this standard to: "To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults." Do you agree with this Purpose? If not, please provide specific suggestions for improvement in the comment area.**

Summary Consideration:

Approximately 2/3 of respondents supported the changes made to the Purpose.

Several commenters suggested potential changes to the Purpose statement. Among them were: change 'desired' to 'acceptable', remove the words 'coordinate' and 'components', change 'coordinate' to 'ensure', add 'to clear faults' to the end of the statement, and add 'time delayed' before Protection Systems. Based on discussions related to these suggestions, the drafting team revised the Purpose as follows: "To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults."

One commenter suggested changing the title of the standard to 'Protection System Coordination for Interconnected Elements'. The drafting team did not make the suggested change. The drafting team believes that the title of the standard should remain "Protection System Coordination for Performance During Faults." The Purpose and Applicability effectively limit the scope of the standard.

There were a few items that related to PRC-001 which were addressed with the response presented to the comments on questions #6 and #7.

Public Service Enterprise Group	No	As a Results-Based Standard, ?coordinate? should be removed from the Purpose. We suggest that the Purpose should be ?To ensure that Protection Systems involving Interconnected Elements operate in the desired sequence during Faults.?
Response: Thank you for your comment. The drafting team believes that "coordinate" is a necessary part of the Purpose for this Results-Based Standard. The last clause of the Purpose ("such that Protection System components operate in the desired sequence during Faults") is meant to help define "coordinate" when applied to Protection Systems for Interconnected Elements. However, based on overall stakeholder comments, the Purpose statement was modified to: "To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults."		

Wisconsin Electric Power Company	No	Change "in the desired sequence" to "in an acceptable sequence". This better reflects the compromises that may be required by the different entities owning protection systems on an Interconnected Element.
Response: Thank you for your comments. Based on overall stakeholder comments, the Purpose statement was modified to: "To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the <u>intended</u> sequence during Faults."		
Exelon and its Affiliates	No	ComEd believes that the definition should be revised to read ?To coordinate time-delayed Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.?
Response: Thank you for your comment. Coordination includes consideration of more than time-delayed elements, e.g. relay reaches and sensitivities of relay pickups. Based on overall stakeholder comments, the Purpose statement was modified to: "To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the <u>intended</u> sequence during Faults."		
DTE Electric	No	Comments: Since the main purpose of this standard is to assure coordination of BES Interconnected Elements, there should be a provision included to require TOs to provide system fault data to DPs and GOs on a continuous basis so that coordination is performed on BES as well as non-BES elements using the latest data. If complete system fault study files are provided regularly (bi-annually?), projects can be completed using the latest data and not subject to re-evaluation when an update is provided by the TO every 60 months.
Response: Thank you for your comment. The drafting team does not agree that more frequent exchanges should be required by this standard. It is noted that each interconnected owner has the ability to request information at any time as part of Requirement R3, Part 3.2. This standard does not prevent an owner from performing more frequent reviews.		
LG&E and KU Services	No	Comments: The expression "the desired sequence" should be replaced with "an acceptable sequence," since the GO and TO may not have the same desires.
Response: Thank you for your comments. Based on overall stakeholder comments, the Purpose statement was modified to: "To		

coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.”		
Florida Municipal Power	No	FMPA continues to believe the greater purpose is to ensure faults are cleared within their critical clearing times and that such consideration is greater than operating within the desired sequence. The same comment would apply to the definition of Protection System Coordination Study.
Response: Thank you for your comment. The drafting team believes that the initial Protection System design and settings take into account the critical clearing times. The drafting team believes that operating within the intended sequence, as stated in both the Purpose and the definition of Protection System Coordination Study, ensures that faults are cleared within their critical clearing times.		
Flathead Electric Cooperative, Inc.	No	In our area, there do not appear to be any issues with lack of protection system coordination and I am unsure if there is really a need for this standard. Their appear to be adequate protection systems standards noted in the "Other Aspects of Coordination of Protection Systems Addressed by Other Projects" section.
Response: Thank you for your comment. The drafting team believes that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.		
ISO RTO Council Standards Review Committee	No	It seems like the scope of the standard as stated in the purpose statement can be misunderstood. Later in the proposed standard, the purpose is narrowed:?Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1.?The SDT should consider revising the purpose to reflect the scope of this standard, e,g. ?,,,operate in the desired sequence to CLEAR faults.? PRC-001 issues; a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. This is a training requirement and as such, it should be transferred to the appropriate PER standards. The SRC supports the project for removing this requirement and moved

		into the PER standards..Providing training evidence does not demonstrate that the (operating personnel of) responsible entities are ?familiar with? the purpose and limitations of protection system schemes applied in its area. c. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. In response to comment submitted by some commenters, the SDT indicates that it ??recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.? We do not agree with this recommendation and hold the view that adding the issue to the NERC Issue Data Base is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT should propose a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee?s advice/direction for appropriate actions. We do not believe that the SDT or staff has brought this to the Standards Committee?s attention. Note that the Standards Committee is responsible for managing the standards development process and as such, can make an informed decision to either request the SDT to expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel. Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. We urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.]

Response: Thank you for your comment on the Purpose for PRC-027-1. The drafting team believes there is no misunderstanding in the Purpose statement. Fault clearing is the only aspect of protection coordination that this standard addresses. The inclusion

of "to CLEAR faults" in the Purpose is unnecessary. **PRC-001 issues:** **The drafting team appreciates your comments regarding PRC-001. After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PER-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.**		
SMUD	No	SMUD believes the purpose of this standard should state: ?To coordinate Protection Systems for Interconnected Connection to help ensure Protection System components operate as expected for off-nominal conditions. We believe that the coordination is an effort to avoid misoperations a condition that may occur if the purpose statement is not met. We further believe that the coordination should not only cover a Fault condition but other intended operation that the protections scheme would cover, i.e. power swing, out of step tripping/blocking, etc.
Response: Thank you for your comments. The drafting team does not believe that the purpose of this standard is to ensure Protection System components operate for all off-nominal conditions. Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. As stated in the Background section of this standard, Protection System responses to power swings, out of step tripping/blocking, etc. are being addressed in other NERC projects.		
City of Tacoma	No	Suggest removing the word ?components.? A Protection System operates together. If the SDT elects to retain the word ?components,? clarification of the intent of this word in this context is requested.
Response: Thank you for your comment. The NERC Glossary of Terms lists five types of Protection System components which must operate together to achieve the intended sequence during Faults. The word "components" was used in the Purpose because protective relays and their settings are not the only aspects of Protection Systems that can impact coordination.		

Southern Company	No	Suggest that "the desired sequence" be replaced with "an acceptable sequence" to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in an acceptable sequence during Faults. e.g. the GO and TO may not have the same desires.
Response: Thank you for your comments. Based on overall stakeholder comments, the Purpose statement was modified to: "To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults."		
NextEra Energy	No	The end of the sentence should read: . . . . desired sequence and time during Faults.
Response: Thank you for your comment. The drafting team believes that desired sequence includes timing; therefore, adding "and time" to the Purpose would be redundant.		
Essential Power, LLC	No	The expression "the desired sequence" should be replaced with "an acceptable sequence," since the GO and TO may not have the same desires.
Response: Thank you for your comments. Based on overall stakeholder comments, the Purpose statement was modified to: "To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults."		
Northeast Power Coordinating Council	No	The wording is redundant. Coordinating Protection Systems mean operating in the desired sequence during faults. The Purpose should just read ?To coordinate Protection Systems for Interconnected Elements?.
Response: Thank you for your comment. The last clause of the Purpose "such that Protection System components operate in the intended sequence during Faults" clarifies what is meant by "… Coordination for Performance During Faults" in the standard's title.		
Texas Reliability Entity	No	We suggest re-wording the second half of the purpose to say ?such that Protection System components operate in the desired sequence to properly isolate Faults?.
Response: Thank you for your comment. The drafting team believes operating in the intended sequence during Faults includes the idea of properly isolating Faults.		

Ameren	Yes	(1) Ameren supports the SERC Protection & Control Subcommittee comments and hereby includes them by reference rather than repeating them all.
Response: Thank you for your comment. Please see the response to the SERC Protection & Control Subcommittee comments (SERC RRO)		
Dominion	Yes	1) The SPC standard drafting team created this result-based standard specifically directed toward Interconnected Facility applications by stating in the current draft that ?PRC027-1, with the stated pupose ?to coordinate Protection Systems for Interconnected Elements?.? . Also in Draft#3 the purpose now places emphasis on ?desired operating sequence? versus Element isolation. To align with this purpose, as previously suggested, we recommend that the title of this standard reflect the revised purpose and be renamed ?Protection System Coordination for Interconnected Elements?.
Response: Thank you for your comment. The drafting team believes that the title of the standard should remain "Protection System Coordination for Performance During Faults." The Purpose and Applicability effectively limit the scope of the standard.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration (?ICLP?)agrees that the updated purpose statement is more appropriate for a BES Reliability Standard. The previous version sought to minimize the faulted elements ? which is a desirable goal in most cases, but may not be the highest priority where multiple interconnected entities are concerned. (Otherwise, the ironic result could be that local service is preserved at the expense of the wider-area system.) The intended Protection System design should predominate, as it will account for any such circumstances.
Response: Thank you for your support.		
Bureau of Reclamation	Yes	Reclamation appreciates and agrees with the drafting team?s clarification of the Purpose section. Reclamation agrees with the drafting team that it is more important for Protection System components to ?operate in the desired sequence during Faults? than to have ?the least number of power system Elements? isolated to clear Faults as previously stated in Draft 2 of the Purpose section.

Response: Thank you for your support.		
Independent Electricity System Operator	Yes	We agree with the revised purpose statement, but reiterate our previous suggestion to add ?settings? after protection system (with the ?s? removed?) to make it clear that it is the coordination of the settings, not the design of protection systems. The SDT?s response to our previous comment indicates that: ??settings? are not the only aspect of Protection Systems that can impact the stated purpose.? We are unable to come up with any specific examples of what other parameters or actions associated with the Protection System of an Interconnection Element that would require coordination to ensure ?Protection System components operate in the desired sequence during Faults?. Please elaborate, or revise the purpose statement accordingly.
Response: Thank you for your comment. The coordination of settings is important to achieving the Purpose of the standard. However, the coordination of settings is not the only aspect of Protection Systems that can impact the ability to achieve the Purpose "to operate in the intended sequence during Faults." Notification of replacement with different types of protective relays, modification of protective relays, changes in communication systems, current transformer ratios and voltage transformer ratios are examples of Protection System information required to achieve coordination.		
Cooper Compliance Corp	Yes	We feel this is a good compromise to making the applicability the Transmission Planner. In our earlier comments we noted that we feel the drafting team should identify the Transmission Planner to be the entity who performs the studies as this is the function identified for the TP. The drafting team responded by stating they changed the Purpose.
Response: Thank you for your support.		
Pepco Holdings	Yes	
Duke Energy	Yes	
FirstEnergy Corp	Yes	

Bonneville Power Administration	Yes	
Madison Gas and Electric Company	Yes	
Associated Electric Cooperative, Inc.	Yes	
Southwest Power Pool	Yes	
SERC RRO	Yes	
JEA	Yes	
PacifiCorp	Yes	
Electric Reliabilty Compliance	Yes	
PJM Interconnection	Yes	
Dynegy	Yes	
Manitoba Hydro	Yes	
American Electric Power	Yes	
ITC	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	

Kansas City Power and Light	Yes	
Clark Public Utilities	Yes	
Xcel Energy	Yes	
Illinois Municipal Electric Agency	Yes	
California ISO		See associated SRC Comments

2. The drafting team modified the proposed definition of Interconnected Element to read as follows: Interconnecting Element: A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). Do you agree with the revised definition? If not please provide specific suggestions for improvement in the comment area.

Summary Consideration:

Based on the comments received, the drafting team made two minor changes to the previous term Interconnected Element. First, the term was changed to Interconnecting Element, and secondly the words 'owned by' was moved to the beginning of a) and b).

The new term reads as follows:

Interconnecting Element: A BES Element that electrically joins Facilities:

a) owned by separate Registered Entities, or

b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Numerous commenters had concerns regarding part b of the definition of Interconnecting Element. The drafting team wants to clarify that the intent of this standard is to promote the coordination of Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults. The drafting team is not trying to be prescriptive how the coordination process is achieved regardless of the organizational structure of the applicable Registered Entity. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."

Organization	Yes or No	Question 2 Comment
Nebraska Public Power District	No	Will there be an expectation that each entity involved with interconnected elements or facilities be pre-identified in any other documentation other than perhaps in each PSCS?
Response: Thank you for your comment. No, there is no such requirement for pre-identification; however, it would be a reasonable expectation that an applicable entity would identify the Interconnecting Elements on its system.		
Dynegy	No	?Please provide more examples of interconnected elements, especially for a merchant generator. It?s not clear if the protection system study should address protection systems for just the generator breaker or also the generator step up transformer, unit auxiliary transformer, or the generator itself. Perhaps this information belongs in the Application Guideline.
Response: Thank you for your comment. Please see Figures #2 and #5 in the standard for examples of generator interconnections. Note that Figure #2 covers the large majority of generator interconnections. The Protection Systems included in the Applicability section of this standard are: Protection Systems: a) installed for the purpose of detecting Faults on Interconnecting Elements, and; b) that require coordination for isolating those faulted Elements.		
Bonneville Power Administration	No	1. In this new term, the use of ?interconnected? implies that the element is connected by another element, which is not what is intended. A more appropriate word would be ?interconnecting? as this indicates that this is the element that connects other elements. 2. The definition as written does not make sense because there is typically not an element that electrically joins facilities owned by separate registered entities. Instead, where the point of interconnection between separate registered entities is made, one entity will own the element on one side of the point of interconnection and the other entity will own the element on the other side of the point of interconnection. The change of ownership is made at a point, not through a commonly-owned element. Since all elements are owned by one entity or the other, there is no element that electrically joins the elements owned by the two entities

Organization	Yes or No	Question 2 Comment
		and nothing that meets the definition provided for an Interconnected Element.3. Part B of the definition does not indicate which element is the Interconnected Element in a system where the same registered entity represents multiple functions. Does this allow the entity to choose which element is considered to be the Interconnected Element? For example, if an entity is both a generator owner and transmission owner they will own all elements from the generator to and including the transmission system, with no change of ownership. There is no clear point where the generator function stops and the transmission function begins. Which element will be considered to be the Interconnected Element and required to comply with this standard?
Response: Thank you for your comments. **1. Thank you for distinguishing between "interconnected" and "interconnecting" and the SPCSDT accepts your suggestion.** **2. The Interconnecting Element is the BES Element being protected by the Protection Systems requiring coordination. Please reference the figures within the Guidelines and Technical Basis section of the standard for more explanation.**		
ReliabilityFirst	No	ReliabilityFirst requests clarification on the term ?Interconnected Element.? First, is the term ?facilities? referring to the NERC Glossary of Terms defined term ?Facility?? If so, this term needs to be capitalized. Furthermore, if this is the intent, with a Facility being defined as ?a set of electrical equipment that operates as a single Bulk Electric System Element?, there seems to be no need to add the term ?BES? to the beginning of the definition. a. ReliabilityFirst recommends capitalizing the term ?facility? and b. deleting the term ?BES? from the definition.
Response: Thank you for your comment. **a. Your suggestion of capitalizing "Facility" is accepted.** **b. The drafting team believes the inclusion of BES is appropriate to remove any doubt as to which elements this standard**		

Organization	Yes or No	Question 2 Comment
applies to.		
Associated Electric Cooperative, Inc.	No	AECI remains unclear as to the intent and effect of PRC-027-1?s definition for ?Interconnected Element? with respect to clause-b, ?the same Registered Entity?? clause. As written, this clause potentially captures all internal BES Elements that electrically joins any internal facilities owned within a Registered Entity that represents multiple functional entity responsibilities. Does clause-b intend to scope additional BES Elements: 1) that electrically join facilities between legally distinct entities within the same Registered Entity (including a JRO) that represents multiple functional entity responsibilities (Distribution Provider, Generation Owner, or Transmission Owner), or 2) that (even within a JRO) electrically join only functionally distinct facilities within the same Registered Entity that represents different functional entity responsibilities such that internally included Elements join: DP-GO, DP-TO, GO-TO, while internally Excluded Elements join: DP-DP, GO-GO, TO-TO?
Response: Thank you for your comment. The intent of clause b) in the definition of Interconnecting Element is to address the situation you cite in item 2.		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by Florida Municipal Power Agency.
Response: Thank you for your comment. See comments to Florida Municipal Power Agency.		
Flathead Electric Cooperative, Inc.	No	It is difficult to support the current definition that relies on the BES Element language from the BES definition process that has not been finalized. In our case, there are elements that would not be in scope for Interconnected Element consideration, but if there is no finalization of the BES definition and this standard moves ahead, the heart of this definition would be in flux. More specificity in what

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>equipment we are really talking about here might be helpful in the absense of a settled definition of a BES element.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. Regardless of how the “BES” is finally defined, the use of the term “BES” will remain unchanged in this standard.</td></tr>
<tr><td>JEA</td><td>No</td><td>Most of the standard (R1.2, R2.2.1, R3 & R4) should not be applicable to a Registered Entity that represents multiple functional entity where the same system protection group has responsibility for the protection of their entire control area.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: “In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities.”</td></tr>
<tr><td>Madison Gas and Electric Company</td><td>No</td><td>NSRF?s concern with the proposed definition is related to part B of the definition, on how to prove compliance in case of a vertically- integrated Registered Entity where one department is responsible for performing PSCS and the same Registered Entity is performing multiple functions. Recommend that the measures be updated for both part A and part B or clarity within the RSAW.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: “In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities.” The drafting team reviewed the Measures and does not believe the Measures require updating. The Measures provide examples of evidence that can be used to demonstrate compliance.</td></tr>
<tr><td>Southwest Power Pool</td><td>No</td><td>Our concern with the way the definition is worded relates to how to prove compliance between separate entities as well as entities within a vertically integrated utility. How would a Registered Entity actually show that the proper</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
		coordination took place? In some instances it appears that evidence would have to be provided for coordination within the same department of an entity. On the other hand, if separate entities are involved, just what evidence would be required to show adequate coordination? Does this need to be formal documentation indicating all the owners of the interconnecting facility?
Response: Thank you for your comment. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities." The Measures provide examples of evidence that can be used to demonstrate compliance.		
Pepco Holdings	No	PHI suggests the definition of Interconnection Element be revised as follows:?Interconnection Element: A BES element that electrically joins facilities a) owned by separate Registered Entities, or b) operated by separate Functional Entities (Distribution Provider, Generation Owner, or Transmission Owner) within the same Registered Entity.? Without this change the existing language could be mis-interpreted as requiring a documented Protection System Coordination Study on each and every internal BES transmission line (transmission line to transmission line coordination) within a Registered Entity?s system, just because the Registered Entity has registered as multiple Functional Entities, and despite the fact that all the lines in question are owned and operated by the same Transmission Owner Functional Entity. The intent of the standard is to address coordination of interconnected elements between separate Registered Entities or between separate functional entities within the same Registered Entity.
Response: Thank you for your comment. Based on stakeholder comments, the drafting team modified the definition to read: **Interconnecting Element: A BES Element that electrically joins Facilities:**		

Organization	Yes or No	Question 2 Comment
a) owned by separate Registered Entities, or b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). The drafting team intends for this standard to address coordination of Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements, and that require coordination for isolating those faulted Elements - between separate Registered Entities or between separate functional entities within the same Registered Entity.		
Bureau of Reclamation	No	1. Reclamation appreciates the drafting team?s clarification of the definition of Interconnected Element to specify that Interconnected Elements must be ?BES Elements.? However, Reclamation believes that the addition of part b) of the definition is problematic. Reclamation believes that ?Interconnected Elements? covered by the standard should only join facilities owned by separate Registered Entities as specified in part a) of the definition. Reclamation is not clear on how an entity would document internal coordination of Protection System Coordination Studies for the TO and GO arms of the same entity. Reclamation notes that the examples provided by the drafting team in the Application Guideline Diagrams appear to describe only Interconnected Elements at the point of demarcation between separate registered entities. At some Reclamation facilities, the same staff members coordinate TO and GO relay settings, so it is not clear how the studies and concurrence required under R1-R4 would be accomplished. Reclamation believes that PRC-023, PRC-025, and other standards will ensure that TO and GO relay settings are appropriate, and that PRC-027 should only address relay setting coordination where facilities join separate Registered Entities. In addition, the Background section of the standard explains that one purpose of the standard is to address the August 14, 2003 blackout report recommendation on the need to ?address ?the appropriate use of time delays in relays,? by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve

Organization	Yes or No	Question 2 Comment
		coordination. Consistent with this rationale, Reclamation recommends that the drafting team modify the definition of Interconnected Element to read, ?A BES Element that electrically joins facilities owned by separate Registered Entities.? 2. Finally, Reclamation notes that the definition of Elements in the NERC Glossary is, ?Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.? By incorporating the term Element, PRC-027-1 perpetuates the ambiguous definition of Elements by including the term ?such as,? which creates an open-ended list of possible Elements. Reclamation believes it would be helpful for entities to have a better defined list of possible ?Interconnected Elements? so that Entities can ensure compliance.
Response: Thank you for your comment. 1. **For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."** 2. **The drafting team believes the use of the NERC Glossary of Terms "Element" is appropriate within the context of the term "Interconnecting Element". Please reference the figures in the Guidelines and Technical Basis section of the standard for various examples of Interconnecting Elements.**		
LG&E and KU Services	No	Section b) of the definition should be deleted. An ?interconnected element? subject to these requirements should not include elements owned/operated by the same registered entity. To minimize the impact of equipment outages under fault conditions, coordination studies are routinely performed by vertically integrated utilities that own and operate facilities that extend from generation plants to distribution pole top transformers. The requirements appear to be intended to insure this same level of coordination is achieved between disparate

Organization	Yes or No	Question 2 Comment
		owner/operators of upstream and downstream facilities. Moreover, as used throughout industry the term interconnected generally refers to electrically contiguous facilities belonging to different operators. After eliminating part b) of the definition, PRC-027 requirements would still apply to vertically integrated registered entities at each point of interconnection with facilities owned/operated by unaffiliated and separately registered entities performing as, e.g., DPs, GO/GOPs, neighboring TOs as appropriate.
Response: Thank you for your comment. The drafting team believes item b) is necessary because in some vertically integrated utilities, coordination related to different functional entities may not be performed by the same protection group. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."		
SMUD	No	SMUD believes the Interconnected Element should be defined as those BES elements that electrically join two or more facilities. SMUD disagrees with differentiating ownership as this delineates those requirements based upon ownership causing confusion and an administrative burden for those entities that solely own and coordinate protection components to demonstrate compliance for internal notifications.
Response: Thank you for your comment. The drafting team disagrees with your suggested change to the definition. The drafting team intends for this standard to address coordination of Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements, and that require coordination for isolating those faulted Elements - between separate Registered Entities or between separate functional entities within the same Registered Entity.		
ITC	No	1. The Applicability section 4.2 defines ?facilities? as protection systems with the purpose of detecting BES faults on Interconnected Elements. Therefore, in example Figure 4 the DP does not own ?facilities? and the transmission line or tap are not an Interconnected Element. The definition of Interconnected Element should reflect

Organization	Yes or No	Question 2 Comment
		this fact and Figure 4 should be corrected. If the intention is that Figure 4 should be an Interconnected Element so that R2 still applies, then clarification that Interconnected Elements does not require Applicability section 4.2 defined facilities is required. 2. ITC Holdings engineers perform coordination at Interconnected Elements between ITC Holdings subsidiaries ITCTransmission and METC, both registered TOs. The definition should exclude applications such as this, where the only outcome is increased administrative burden to be auditable with no reliability benefit to BES.
Response: Thank you for your comment. 1. **The drafting team revised Figures 3 and 4 and the associated texts for clarity.** 2. **The drafting team disagrees with your premise. The drafting team intends for this standard to address coordination of Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements, and that require coordination for isolating those faulted Elements - between separate Registered Entities or between separate functional entities within the same Registered Entity. For the case where two registered entities with the same protection group are doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."**		
Florida Municipal Power	No	1. The definition poses a problem with the second bullet. It is relatively easy to determine the "boundaries" between separate Registered Entities. It can be difficult to determine the boundaries between where an entity's separate registrations begin and end. Just look at how difficult determining the boundaries of the BES is, and witness the challenges of the GO/TO project where the boundaries between GO and TO are/were not clear. This standard now requires us to also draw the boundary between TO and DP. For example, let's take a step-down transformer to distribution that is connected to a ring bus or breaker-and-a-half scheme. Typically, the high side relays for the transformer will be connected to the current transformers on the breaker bushings within the bus arrangement, which are part of the BES. Those relays

Organization	Yes or No	Question 2 Comment
		are not only there to protect the transformer (not BES), but, also the bus section within the ring or breaker-and-a-half scheme (which is BES). So, are those relays (e.g., differential, directional overcurrent looking into the transformer) owned by the TO or DP registration? 2. It also seems to FMPA that the reliability objective should not be limited to coordinating relays at just the "boundaries"; so, maybe one way to solve the boundary issue is to ignore it and just require a Registered Entity to coordinate its relays that protect the BES. This would expand the scope of the standard even more than the current PRC-001 to the proposed PRC-027, but, it would meet the reliability objective better. Another way to do it is to coordinate all at > 200 kV following PRC-023, and coordinate at the boundaries between entities (not registrations), at all BES.
Response: Thank you for your comment. **1. In the example you cite, if the Distribution Provider has Protection Systems that meet the Applicability; then they are subject to this standard.** **2. The standard drafting team disagrees with both of your suggestions regarding the scope of the standard. This standard is only applicable to Protection Systems on Interconnecting Elements as stated in the Applicability.**		
City of Tacoma	No	There is some concern about the language in part b of the proposed definition of an Interconnected Element. In some cases, a Registered Entity may have one engineering group that is responsible for all Protection Systems, regardless of registered function. Part b of the proposed definition seems to suggest that documented PSCSs, including coordination activities, could be required by proposed PRC-027-1 even if the same engineering group is responsible for all Protection Systems associated with the Interconnected Element. A distinction should be drawn between a Registered Entity in which one engineering group is responsible for Protection Systems associated with its DP, GO, and TO functions, as applicable, and another Registered Entity in which a different engineering group is responsible for

Organization	Yes or No	Question 2 Comment
		Protection Systems associated with its DP vs. GO vs. TO functions, as applicable.
Response: Thank you for your comment. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."		
Clark Public Utilities	No	There still is some concern regarding coordination within a Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). This type of Registered Entity is one organization and the standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one entity. The comments below provide specifics of these concerns. In order to address these concerns it is suggested that the words ?separate? and ?same? in this definition be capitalized for reference purposes. The definition should be modified as follows:Interconnected Element: A BES Element that electrically joins facilities owned by:a) Separate Registered Entities, orb) the Same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).
Response: Thank you for your comment. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities." **The drafting team sees no benefit to capitalizing the terms "separate" and "same".**		
Texas Reliability Entity	No	We have concerns with this proposed definition surrounding the current state of the proposed BES definition changes especially in light of the multiple possible exclusions that may be allowed. In ERCOT, there are numerous large private-use-networks (PUNs) with generation behind the fence that could possibly be excluded under the new BES definition, based solely on how much power they export to the

Organization	Yes or No	Question 2 Comment
		grid. If the new definition of the BES grants exclusions to these PUNs, then the PUN as well as the Transmission Owner that connects to the PUN would not be subject to the requirements of PRC-027. In our opinion, this presents a risk to the BES in that there could possibly be protection systems associated with the PUN interconnection that might need to be coordinated to properly respond to faults on the BES or within the PUN. These protection systems should require some level of coordination between the entities involved.
Response: Thank you for your comment. Regardless of how the "BES" is finally defined, the use of the term "BES" will remain unchanged in this standard.		
Manitoba Hydro	Yes	(1) For clarity, consider re-writing the definition as ?A BES Element that electrically joins a Facility owned by: a) a separate Registered Entity, or b) the same Registered Entity that is represented by multiple functional entities (Distribution Provider, Generator Owner, or Transmission Owner).?
Response: Thank you for your comment. The drafting team disagrees with the suggested change; however, based on stakeholder comments, the definition was modified to read: A BES Element that electrically joins Facilities: a) owned by separate Registered Entities, or b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).		
Ameren	Yes	(1) The word ?facilities? should be capitalized, since it is included in the NERC Glossary: ? Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer,

Organization	Yes or No	Question 2 Comment
		etc.)? and ? Element - Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.?
Response: Thank you for your comment. The drafting team made the suggested change.		
Dominion	Yes	1). The word ?facilities? included in the proposed definition, ?Interconnected Element: A BES Element that electrically joins facilities owned by?? should be capitalized as it is included in NERC?s Glossary of Terms Used in NERC Reliability Standards. 2). Dominion agrees with SERC PCS comment: ?As evident by a note in the rational box for R1 (Page 6 of Redline Version) the drafting team recognizes that vertically integrated entities that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves. To ensure that this intent is retained in the final version of the standard it is suggested that this note or some derivative be placed somewhere in body of the standard such as the definition of Interconnected Element or under the requirements.?
Response: Thank you for your comment. **1. The drafting team made the suggested change.** **2. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: “In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities.”**		

Organization	Yes or No	Question 2 Comment
SERC RRO	Yes	As evident by a note in the rational box for R1 (pg. 6) the drafting team recognizes that vertically integrated entities that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves. To ensure that this intent is retained in the final version of the standard it is suggested that this note or some derivative be placed somewhere in body of the standard such as the definition of Interconnected Element or under the requirements.
Response: Thank you for your comment. The Rationale boxes will remain in the final version of the standard; therefore, the drafting team did not insert it elsewhere in the body of the standard.		
DTE Electric	Yes	None
Ingleside Cogeneration LP	Yes	The addition of the modifier ?BES? to describe the applicable Elements is critical in Ingleside?s view. Without it, CEAs may assume that a Fault study is required for an interconnection at any voltage ? an issue highlighted in FERC Order 773 concerning the Definition of the BES.
Response: Thank you for your comment.		
American Electric Power	Yes	The term ?functional entity? is defined in the NERC Glossary of terms and we believe it should be capitalized in this definition.
Response: Thank you for your comment. The term "functional entity" is not in the NERC Glossary of Terms and should not be capitalized.		
Cooper Compliance Corp	Yes	We would like confirmation that this proposed Standard only requires a study for elements that have been determined to be BES elements. For example, a study would not be required on Elements that connect a radial line serving only load because by definition of BES, there are no BES elements to study.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your support. The drafting team agrees with your premise; however, if the radial line is included in the BES and has Protection Systems included in the Applicability of this standard, then the standard would be applicable.		
Kansas City Power and Light	Yes	Yes, as long as the standard only requires documentation in cases where there are neighboring owners that need to agree on protection and control. As an owner of multiple functional entities, we believe that the BES would not benefit by an intra-utility documentation process, not when the required due diligence is already performed within our System Protection Engineering group. Our System Protection Engineering group is already responsible for the coordination of all protection, whether generation, transmission, or distribution.
Response: Thank you for your support. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."		
ISO RTO Council Standards Review Committee	Yes	
Northeast Power Coordinating Council	Yes	
Duke Energy	Yes	
FirstEnergy Corp	Yes	
Essential Power, LLC	Yes	
PacifiCorp	Yes	
Electric Reliabilty Compliance	Yes	

Organization	Yes or No	Question 2 Comment
Southern Company	Yes	
Exelon and its Affiliates	Yes	
Independent Electricity System Operator	Yes	
Public Service Enterprise Group	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	
Wisconsin Electric Power Company	Yes	
NextEra Energy	Yes	
Xcel Energy	Yes	
California ISO		See associated SRC Comments

3. **In Requirement R1, the drafting team modified the time frame to allow entities 60 months to have a documented Protection System Coordination Study (PSCS) completed for each Interconnected Element if no PSCS exists. Note, the drafting team has allowed inclusion of all previously performed PSCS whose summary of results include, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. Do you agree with this revised time frame? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Approximately 70% of respondents supported the modification to the time frame change in R1.

Two commenters thought that 60 months was too long, while one felt that it was too short for some cases and too long for others. The drafting explained that the change was made based on overall industry feedback.

There were several other comments not directly related to the question:

There was a comment related to the various timelines in the standard. The response indicated that the drafting team believes the different time frames are necessary and appropriate for each of the requirements.

Another comment indicated that only the TO should be responsible for the PSCS. The response indicated that the drafting team believes that it is the Protection System owner's responsibility to ensure that a Protection System Coordination Study is performed.

One commenter indicated that there was no basis for the standard and that it just created a documentation requirement. The response indicated that the drafting team believes that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.

One commenter indicated that there was no reliability benefit to reviewing studies that had been completed in the past. The response indicated that the drafting team believes that there is a reliability benefit in ensuring that all existing Protection Systems on Interconnecting Elements have been reviewed.

Two commenters indicated that the standard should not apply to Registered Entities that represents multiple functional entity responsibilities. The response indicated that for the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."

One commenter indicated that the application of redundant Protection Systems would negate the need to perform a PSCS. The response indicated that the application of redundant Protection Systems does not preclude the necessity of ensuring that your Protection Systems are coordinated.

Organization	Yes or No	Question 3 Comment
ATCO Electric	No	- R1 referring to other requirements with different timelines is very confusing to understand and execute. - R1 (and PRC-027-1 draft 3 in general) also has too many timelines: 90 calendar days, 60 calendar months, 12 calendar months, "agreed upon timefram
Response: Thank you for your comment. A process flowchart is included in the Application Guidelines to show how the different requirements are tied together. The drafting team believes the different time frames are necessary and appropriate for each of the requirements.		
ReliabilityFirst	No	a. ReliabilityFirst believes the shift from 48 calendar months to 60 calendar months is an excessive amount of time to allow an entity to perform a Protection System Coordination Study (PSCS). With the effective date of the standard being 12 months beyond the date that it is approved by applicable regulatory authorities, this is essentially giving entities over six years to perform their initial study, for equipment that previously had no study performed. Furthermore, from a reliability perspective, this coordination is most likely already occurring in some capacity, when the interconnection is made, and entities should not require this excessive timeframe to perform the study (i.e., as quoted from the SDT: ??there is no evidence of widespread miscoordination of Protection Systems associated with Interconnected Elements??). ReliabilityFirst recommends a 24 calendar month implementation timeframe to limit any potential reliability issues as a result of shortcomings in the existing set of Standards.
Response: Thank you for your comment. The time frame was increased to 60 months based on the majority of feedback from stakeholders.		
Madison Gas and Electric Company	No	As currently written, each TO, GO and DP are required to perform a PSCS. This will lead to multiple efforts by each entity. Recommend that GO and DP be removed from this Requirement. Since the TO has access to the hierarchy of systems

Organization	Yes or No	Question 3 Comment
		(Interconnected Elements) they are positioned to request current protection system settings from the GO and DP and then perform a PSCS. They can then request adjustments by the GO and DP in order to assure a more secure system.
Response: Thank you for your comment. The drafting team believes that it is the Protection System owner's responsibility to ensure that a Protection System Coordination Study is performed.		
Bonneville Power Administration	No	BPA believes that the requirement to provide a protection system study for each interconnected element is onerous, and as a result, any amount of time is too short. While beneficial to periodically perform fault studies and review protection system coordination, the creation of a NERC standard to require reviews for Interconnected Elements on a rigid time frame is likely to be counterproductive for the following reasons: a. There is nothing unique about the Protection Systems for Interconnected Elements compared to other Protection Systems that warrants this special treatment. If this standard is deemed necessary, the only logical consequence is that similar standards must be created for all protection systems. Trying to coordinate Protection Systems to comply with numerous standards will limit flexibility. Diverting resources from addressing Protection System problems to completing compliance documentation makes the system less reliable, not more. b. This standard provides no quality benefit to the Protection System Coordination process. It only increases the documentation burden, which is just as likely to decrease the quality of the review as it is to improve it. c. There are an enormous number of things that entities do to keep the BES reliable. If NERC wishes to regulate and enforce all of these things, it will come at an enormous cost to consumers of electric power. Cost increases are already being experienced due to the present standards. Since there has been no widespread problem with Protection System coordination between entities, this particular issue should not be the subject of a standard. d. Any specified time frame for a Protection System Coordination review will be too

Organization	Yes or No	Question 3 Comment
		long for some situations and too short for others. The Protection System Engineers within the entities are in the best position to determine an appropriate review interval for each element.
Response: Thank you for your comment. **a, b, c, d. The drafting team believes that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.**		
Florida Municipal Power	No	1. Five (5) years seems way too long for an initial coordination study. We should pick a period of time that both industry and FERC will likely approve, maybe something like two (2) years. 2. Other comments on R1:FMPA's interpretation of the Applicability combined with the standard is that remote back-up protection is included as it was "installed for the purpose of detecting Faults on Interconnected Elements". This becomes ambiguous for directional, inverse time ground current protection whose reach can vary with ground current, or with such relays and zone distance relays with changes in system configuration. FMPA's interpretation is that the Applicability is to the maximum reach of such relays; is that the intent of the SDT? 3. Bullet 1.2 is ambiguous in its use of the term "owner"; especially in combination with the definition of Interconnected Element that makes the distinction between different registered functions within the same entity. Is the owner the entity, or the registered function? We assume the "owner" is the entity; is that the intent of the SDT?
Response: Thank you for your comment. **1. The time frame was increased to 60 months based on feedback from stakeholders.** **2. The standard is applicable to: Protection Systems: a) installed for the purpose of detecting Faults on Interconnecting Elements, and; b) that require coordination for isolating those faulted Elements.**		

Organization	Yes or No	Question 3 Comment
3. The "owner" is the functional entity that owns the Protection System.		
Ingleside Cogeneration LP	No	ICLP mostly agrees with rationale for R1 that states ?The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame <than 60 months>.? We would take that one step further and argue that far more critical coordination occurs in UVLS, UFLS, SPS, and distance relay schemes ? and is already covered in other NERC standards. Fault analyses are comparatively basic, and do not require a re-evaluation unless a material change is made in the local grid. This means that a Generator Owner should be able to make a simple confirmation that nothing has changed since the previous time a Fault study was performed ? usually during commissioning or a major reconfiguration. If the TO wants a full Fault evaluation due to a change in the local transmission system, they are free to do so under R1.1.2. Requiring every GO to produce the results of a study that took place years in the past serves no reliability purpose.
Response: Thank you for your comment. The drafting team believes that there is a reliability benefit in ensuring that all existing Protection Systems on Interconnecting Elements have been reviewed and it is the owner's responsibility to ensure a study has been performed. Requirement R1, Part 1.2 describes the minimum that a summary of the results of a PSCS performed pursuant to Requirement R1, Part 1.1 must include. If the GO has these results, they can meet the intent of the requirement by sending the results to the other owner(s) within 90 days.		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by Florida Municipal Power Agency.
Response: Thank you for your comment. See response for Florida Municipal Power Agency.		
Wisconsin Electric Power Company	No	Requirement 3.3 needs to be revised to allow an entity the flexibility to make emergency changes to protection systems or settings that are necessary to correct a reliability problem. The current draft allows such changes only when a failure occurs.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. Requirement R3 covers the provision of information to other owners after replacements have occurred. The drafting team is not precluding any maintenance work in the requirement. Requirement R3, Part 3.3 mandates that the entity provide information regarding whatever maintenance was done within 30 calendar days of completing the maintenance.		
SMUD	No	The revised time frame of 60 months is agreeable, however, requirement 1.2 should not be applicable to any Interconnection Element owners that are one of the same Registered Entity that represents multiple functional entity responsibilities. There are several Registered Entities that have only one person or department within a utility that is responsible for protection system coordination for all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the Protection System Coordination Study to provide a copy to ?other owners?. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner.
Response: Thank you for your comment. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."		
Clark Public Utilities	No	1. The revised time frame of 60 months is agreeable, however, requirement 1.2 should not be applicable to any Interconnection Element owners that are part of the ?same Registered Entity that represents multiple functional entity responsibilities.? Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the Protection System Coordination Study to provide a copy to ?other owners?. The standard should allow for the treatment of all of the registered functions within a

Organization	Yes or No	Question 3 Comment
		Registered Entity that represents multiple functional entity responsibilities collectively as one owner. 2. Since the definition of Interconnection Elements incorporates the concept of ?Separate Registered Entities and ?Same Registered Entities? it is suggested that the wording be modified to incorporate theses terms as follows:R1.2 Within 90 calendar days after the completion of each PSCS, provide to the other Separate Registered Entities that are owner(s) of the Protection System(s) associated with the Interconnected Element(s), a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed).
Response: Thank you for your comment. 1. **For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."** 2. **The drafting team disagrees with your suggested changes to Requirement R1, Part 1.2 and made no changes.**		
LG&E and KU Services	No	There is no basis for performing studies every 60-months. Such studies should be performed when necessary based on predetermined criteria set forth in the standard. There is no evidence of wide spread miscoordination of Protection Systems associated with Interconnected Elements. In fact, none of the recent blackouts resulted from miscoordination of protective settings.
Response: Thank you for your comment. Requirement R1 does not mandate that a PSCS be performed every 60 months; however, it does state the conditions that require a PSCS be performed.		
Exelon and its Affiliates	No	We do not believe that a mandatory PSCS needs to be completed for each interconnected element as stated in Requirement 1. We believe that the design of the Protection System for an interconnected element must first be considered

Organization	Yes or No	Question 3 Comment
		before requiring a PSCS. In cases where high speed protection schemes are redundant, the reliance on time-delayed backup elements would require at least 2 protection system element contingencies. We propose that redundancy should consist of the use of two separate relays and auxiliary relays as per the redundancy test required in the NERC board-approved TPL-001-2 standard. If failure of a single relay or auxiliary relay results in reliance on time delayed back-up protection, we agree that a PSCS should be required, and consequently would agree to the 60 month time frame.
Response: Thank you for your comment. The application of redundant Protection Systems does not preclude the necessity of ensuring that your Protection Systems are coordinated.		
Northeast Power Coordinating Council	Yes	60 months is an adequate and appropriate period which balances the interest of reliability with the economics related to engineering costs.
Response: Thank you for your support.		
Duke Energy	Yes	Duke Energy agrees with the changes made by the SDT to extend the period to 60 months.
Response: Thank you for your support.		
DTE Electric	Yes	None
Response: Thank you for your support.		
ISO RTO Council Standards Review Committee	Yes	SRC chooses not to respond to this question, please disregard the response as it was selected in error and could not be deleted.
Pepco Holdings	Yes	

Organization	Yes or No	Question 3 Comment
FirstEnergy Corp	Yes	
Dominion	Yes	
Essential Power, LLC	Yes	
Associated Electric Cooperative, Inc.	Yes	
Southwest Power Pool	Yes	
SERC RRO	Yes	
JEA	Yes	
City of Tacoma	Yes	
PacifiCorp	Yes	
Electric Reliabilty Compliance	Yes	
PJM Interconnection	Yes	
Bureau of Reclamation	Yes	
Southern Company	Yes	
Dynegy	Yes	
Manitoba Hydro	Yes	
Independent Electricity System	Yes	

Organization	Yes or No	Question 3 Comment
Operator		
Texas Reliability Entity	Yes	
American Electric Power	Yes	
ITC	Yes	
Public Service Enterprise Group	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Ameren	Yes	
Kansas City Power and Light	Yes	
NextEra Energy	Yes	
Xcel Energy	Yes	
California ISO		See associated SRC Comments

4. In Requirement R2, the drafting team modified the time frame to 60 months for either conducting a Fault current review or provide a technical justification as to why a Fault current review is not necessary. Do you agree with this revision to Requirement R2? If not, please provide specific suggestions for improvement in the comment area.

Summary Consideration:

No specific changes to the timeframe were made based on comments recieved, however, overall discussion within the drafting team related to comments received did result in the removal of the provision that the Transmission Owner could provide a technical justification for not conducting the 60 month fault current review specified in Requirement R2.

Comments related to the specific question were as follows:

There should be a provision included to require TOs to provide system fault data to DPs and GOs on a continuous basis The response indicated that the drafting team does not agree that more frequent exchanges are required because each interconnected owner has the ability to request information at any time as part of Requirement R3 Part 3.2. This standard does not prevent an owner from performing more frequent reviews.

Additional comments are noted below:

Requirement R2 (and PRC-027-1 draft 3 in general) also has too many timelines and is confusing. The response noted that a process flowchart is included in the Application Guidelines to show how the different requirements are tied together. The drafting team believes the different time frames are necessary and appropriate for each of the requirements.

It should be sufficient that the TO show that a coordinated assessment takes place when an appropriate trigger condition occurs. The response indicated that the purpose of Requirement R2 is for the TO to inform the other party of a change in fault currents of 10% or more which the drafting team believes is an appropriate trigger to investigate the need for a review of Protection Systems. Note that the drafting team allows an entity (a GO in your case) to provide a technical justification explaining why changes in bus Fault current do not affect its coordination.

Requirement R2 should not apply to Registered Entities that represents multiple functional entity responsibilities. The response indicated that for the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: “In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities.

One commenter disagreed that a technical justification should be required for relays and schemes that are unaffected by the level of Fault current. The response indicated that The drafting team believes an initial technical justification is required to demonstrate that the Protection Systems are not impacted by changes in Fault current. A GO is allowed to reuse its previous technical justification provided it is still valid to justify why a new PSCS is not required (as in Requirement R1, Part 1.1.2).

Organization	Yes or No	Question 4 Comment
ATCO Electric	No	- R2 referring to other requirements with different timelines is very confusing to understand and execute. - R2 (and PRC-027-1 draft 3 in general) also has too many timelines: 90 calendar days, 60 calendar months, 12 calendar months, "agreed upon timefram
Response: Thank you for your comment. A process flowchart is included in the Application Guidelines to show how the different requirements are tied together. The drafting team believes the different time frames are necessary and appropriate for each of the requirements.		
Ingleside Cogeneration LP	No	Although ICLP is not a Transmission Owner, we will be impacted if the TO?s assessment shows a material change in Fault current has occurred in an interconnecting element. We believe our TO has every economic and reliability incentive to contact us if a modification threatens the transmission network. It should be sufficient that the TO show that a coordinated assessment takes place when an appropriate trigger condition occurs.
Response: Thank you for your comment. The intent of Requirement R2 is for the Transmission Owner to inform the other entity of a change in Fault currents of 10% or more which the drafting team believes is an appropriate trigger to investigate the need for a review of Protection Systems. Note that the drafting team allows an entity (a GO in your case) to provide a technical justification explaining why changes in bus Fault current do not affect its coordination.		

Organization	Yes or No	Question 4 Comment
DTE Electric	No	Comments: Since the main purpose of this standard is to assure coordination of BES Interconnected Elements, there should be a provision included to require TOs to provide system fault data to DPs and GOs on a continuous basis so that coordination is performed on BES as well as non-BES elements using accurate data. If complete system fault study files are provided regularly (bi-annually?), projects can be completed using the latest data and not subject to re-evaluation when an update is provided by the TO every 60 months. It is critical that fault study data file compatibility exists between the short circuit programs of the different entities.
Response: Thank you for your comment. The drafting team does not agree that more frequent exchanges are required because each interconnected owner has the ability to request information at any time as part of Requirement R3 Part 3.2. This standard does not prevent an owner from performing more frequent reviews.		
Bonneville Power Administration	No	Please see comments for Question 3.
Response: Thank you for your comment. See response for Question #3.		
SMUD	No	Please see our comments in Question #3; The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner.
Response: Thank you for your comment. See response for Question #3.		
LG&E and KU Services	No	See response to question 3 above.
Response: Thank you for your comment. See response for Question #3.		
Clark Public Utilities	No	1. The revised time frame of 60 months is agreeable, however, requirement 2.2.1 should not be applicable to any Interconnection Element owners that are part of the ?same Registered Entity that represents multiple functional

Organization	Yes or No	Question 4 Comment
		entity responsibilities.? Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the updated Fault current study to provide the updated Fault current values (Iscs) to ?each owner? of the Protection System associated with the Interconnected Element. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. 2. Since the definition of Interconnection Elements incorporates the concept of ?Separate Registered Entities and ?Same Registered Entities? it is suggested that the wording be modified to incorporate theses terms as follows:R2.2.1 Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each Separate Registered Entity that is an owner of the Protection System associated with the Interconnected Element.
Response: Thank you for your comment. 1. **For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."** 2. **The drafting team disagrees with your suggested changes to Requirement R1, Part 1.2 and made no changes.**		
Exelon and its Affiliates	No	This requirement unnecessary burden on the Generation Owner. The fault current seen by Generator Owner?s protective devices depend on the Generation Owners equipment (e.g., the main generator and transformers). So unless those are replaced there should be no requirement on the Generator Owner to review the protection coordination study due to change in fault current at the interconnecting bus which will be due to grid changes. The Transmission Owner will be reviewing

Organization	Yes or No	Question 4 Comment
		those changes and will be coordinating if needed with the Generator Owner. Therefore these requirements should not be applicable to Generation Owner. [Requirement R1 1.1.2 and Requirement R 4 4.1 should also not be applicable to Generator Owner for same reason].Need to identify which elements of Generator Owner?s protection system are included in this Standard and provide specific criteria for showing coordination with TOs protective devices.
Response: Thank you for your comment. The drafting team allows an entity (a GO in your case) to provide a technical justification explaining why changes in bus Fault current do not affect its coordination.		
Public Service Enterprise Group	No	We agree with that the 60 months is adequate; however, we disagree that a technical justification should be required for relays and schemes that are unaffected by the level of Fault current. See our proposed language changes in 8.a below.
Response: Thank you for your comment. If you meet the qualifications regarding the Applicability section of the standard: e.g., you are one of the owners listed in the Functional Entities section 4.1 and you own facilities as described in the Facilities section 4.2 of the standard, the standard is applicable to you. The drafting team believes an initial technical justification is required to demonstrate that the Protection Systems are not impacted by changes in Fault current. A GO is allowed to reuse its previous technical justification provided it is still valid to justify why a new PSCS is not required (as in Requirement R1, Part 1.1.2).		
Ameren	Yes	(1) The "maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus" could either be the total Fault current at that bus, or the Fault current flowing through the Interconnected Element. Our reading of R2, Part 2.2 "used in the most recent PSCS" is that it depends on what the entity used in their study.
Response: Thank you for your comment. The drafting team intended the standard to specify the total Fault current at the interconnecting bus(s).		
Northeast Power Coordinating Council	Yes	60 months is an adequate and appropriate period which balances the interest of reliability with the economics related to engineering costs.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your support.		
Duke Energy	Yes	Duke Energy agrees with the changes made by the SDT to extend the period to 60 months.
Response: Thank you for your support.		
ISO RTO Council Standards Review Committee	Yes	SRC chooses not to respond to this question, please disregard the response as it was selected in error and could not be deleted.
Florida Municipal Power	Yes	
Pepco Holdings	Yes	
FirstEnergy Corp	Yes	
Dominion	Yes	
Essential Power, LLC	Yes	
Madison Gas and Electric Company	Yes	
Associated Electric Cooperative, Inc.	Yes	
Southwest Power Pool	Yes	
SERC RRO	Yes	
JEA	Yes	

Organization	Yes or No	Question 4 Comment
City of Tacoma	Yes	
PacifiCorp	Yes	
Electric Reliabilty Compliance	Yes	
PJM Interconnection	Yes	
Bureau of Reclamation	Yes	
Southern Company	Yes	
Dynegy	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
Texas Reliability Entity	Yes	
American Electric Power	Yes	
ITC	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	
Flathead Electric Cooperative,	Yes	

Organization	Yes or No	Question 4 Comment
Inc.		
Wisconsin Electric Power Company	Yes	
NextEra Energy	Yes	
Xcel Energy	Yes	
Illinois Municipal Electric Agency	Yes	
California ISO		See associated SRC Comments
Kansas City Power and Light		The modification to a longer time frame is acceptable. However, we do not agree that there is adequate justification for requiring a fault current review every five years. Relay settings that are valid today will remain valid until changes are made at our end of an interconnected element or when another Registered Entity notifies us of change. A technical justification that is valid today will remain valid until changes are made to the BES within our system or a neighboring owner?s system.
Response: Thank you for your comment. The drafting team believes that Fault current review and notification should remain in the standard. It is noted that upon notification, the other owner can review a previously developed technical justification and if still valid use it as reason not to perform a new PSCS.		

5. **In Requirement R4, the drafting team has clarified the expectation of what a response to a review of the summary results of a Protection System Coordination Study should include. The options are as follows: • Accepting the results, or • Rejecting the results and suggesting modifications to resolve any identified coordination issues. Do you agree with this revision to Requirement R4? If not, please provide specific suggestions for improvement in the comment area.**

Summary Consideration:

Approximately 70% of the respondents supported the previous changes made to R4.

To address Question 5 comments and additional comments by balloters posed in other ballot Questions, the SDT separated the requirements of R4 into two revised requirements, R4 and R5. The new requirement R4 addresses only the receipt of a PSCS or technical justification and presents modified response alternatives of either; "was reviewed and no coordination issue(s) were identified" or "was reviewed and providing notification of any identified coordination issues(s)". R4 will retain the "90 calendar days" or "agreed-upon schedule" time frame measures for this requirement. The new R5 addresses the implementation of the changes associated with R3, Part R3.1, so that are no outstanding coordination issues prior to implementation.

Additional comments received not addressed above are as follows:

Comment concerning the response will not be in a timely manner and the sending entity could conceivably be found non-compliant if an entity receiving the results does not respond within 90 days. The response indicated that: The entity not responding in a timely manner may be in violation of Requirement R4.

Other Comments related to the potential conflict with the existing terms and conditions of a generator interconnection, and legal requirements to treat all GOs equally. The response indicate that: The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated. Additionally, the Standard Drafting Team agrees that contractual rights must be adhered to, including notice and approval rights. The SDT believes that the standard as drafted does not preclude those contracts, but does address instances where a contract may not address modifications. The phrase "according to an agreed upon schedule" in Requirement R4 provides an avenue to follow the terms of the contract.

A commenter was concerned about the ability to reach agreement when critical replacements are made during unit outages. The response indicated that the drafting team believes the exchange of Protection System information is critical to the reliability of the BES; therefore, any planned changes need to follow the timetables established in the standard. In the case you cite of critical changes made during generation outages, Requirement R3, Part 3.3 allows emergency replacements to be made. Note that the requirement allows agreed upon timetables which could be significantly shorter than those noted in the standard.

Two commenters were concerned that the coordination solution will result in unintended consequences for the Transmission Operator. Should there be a notification requirement for the TOP. The response indicated that the situation described is covered within the TOP group of Reliability Standards which cover notifications of situations that potentially pose a risk to the reliability of the BES, and is outside the scope of PRC-027-1.

Organization	Yes or No	Question 5 Comment
Nebraska Public Power District	No	In theory I understand the drafting team stating: "The drafting team believes that any conflict resolution should be handled through normal business practices. The old Measure M9 (new Measure M10) has been modified as follows: Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted. The drafting team believes the requestor cannot be held accountable when the other party does not respond". However, I don?t believe that we can predict or project how an audit or enforcement team will apply or misapply this requirement which is cause for concern. There are utilities that will respond but may not respond in a timely manner. This puts all entities unfairly under scrutiny. Perhaps some form of clarification could be added to the application guidelines or another location for example.
Response: Thank you for your comment. The role of the drafting team is to draft a standard that minimizes the probability that an auditor could misinterpret the intent of the standard's requirements. The drafting team has expressed to NERC staff the desire to participate in the development of the RSAW. The entity not responding in a timely manner may be in violation of Requirement R4.		
LG&E and KU Services	No	90-days is not in all cases the appropriate time period to review such results. The terms and conditions for generator interconnections are regulated by FERC or state

Organization	Yes or No	Question 5 Comment
		PUCs. The proposed reliability standard should clearly state that responsible entities are not obligated to take any actions that are inconsistent with the rights of the parties under any interconnection or similar agreements. Such agreements typically address the procedures for making modifications to a party?s facilities that may affect the other party and the required notice and approval rights. The standard should not seek to impose any requirements that are inconsistent with these contractual rights. R4.1 speaks of sharing only, ?summary results,? but the Application Guidelines on p.24 lists as examples ?power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings.? We recommend that the above list be preceded with the words ?summaries of.?
Response: Thank you for your comment. The drafting team agrees that contractual rights must be adhered to, including notice and approval rights. The SDT believes that the standard as drafted does not preclude those contracts, but does address instances where a contract may not address modifications. The phrase "according to an agreed upon schedule" in Requirement R4, R4.1 provides an avenue to follow the terms of the contract. **Requirement R4, Part 4.1 refers to "summary results of a PSCS". The drafting team agrees that a "summary" of the PSCS is appropriate. The Application Guidelines includes the broader aspect of information that may not lend itself to a "summary", such as a schematic or a drawing. The information should be conveyed as convenient and agreed upon by both the sender and the recipient.**		
Flathead Electric Cooperative, Inc.	No	Although well-intended, this seems like a difficult thing to document for audit if there are legitimate back and forth over a long period of time.
Response: Thank you for your comment. As you suggest, there may be instances where substantial back and forth comments could occur; in those cases the parties may wish to retain the correspondence: however, the documentation of the final resolution is required.		
Florida Municipal Power	No	Bullet 1.2 is ambiguous in its use of the term ?owner?; especially in combination with the definition of Interconnected Element that makes the distinction between different registered functions within the same entity. Is the owner the entity, or the

Organization	Yes or No	Question 5 Comment
		registered function? We assume the ?owner? is the entity; is that the intent of the SDT?
Response: Thank you for your comment. The “owner” is the functional entity that owns the Protection System.		
Pepco Holdings	No	PHI finds that the revised wording in Section R4 does little to address the root problem associated with mandating mutual agreement. PHI suggests Requirement R4 be removed entirely or extensively re-written to address the concerns outlined below: Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What if agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? This is the

Organization	Yes or No	Question 5 Comment
		problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. It is unreasonable and unfair to hold one party non-compliant due to the failure of another party to reach agreement. Furthermore, in the example provided above, it is a detriment to reliability to delay implementation of the setting change on breaker D just because mutual agreement could not be reached. It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the ?Protection System Study? and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing a clear division of responsibilities and assignment of who will be held non-compliant if agreement cannot be reached is unfair to either party.
Response: Thank you for your comment. The drafting team acknowledges that entities may have differing protection philosophies. The drafting team believes the exchange of Protection System information is critical to the reliability of the BES. Based on yours and other stakeholder comments, the drafting team revised Requirement R4 separating it into two requirements, Requirements R4 and R5.		
Wisconsin Electric Power Company	No	R4 needs revision to better accomodate the entire range of diversities in TO-GO interconnections, especially when agreement cannot be reached between entities, or when agreement cannot be reached in a timeframe required to make critical changes during generating unit outages. R4 also neeeds to include flexibility when the GO is not a vertically integrated utility, and does not have in-house protection engineering resources to respond in the required timeframe. It is unjust to put compliance risk on an entity due to the failure of another entity to reach agreement on settings. In some cases the best that can be expected is for two parties to

Organization	Yes or No	Question 5 Comment
		exchange protection system information and live with a compromise in coordination that allows both to best protect their assets. This may be especially true when generating assets are at stake, and insurance considerations require sensitive protection that may not allow complete coordination.
Response: Thank you for your comment. The drafting team acknowledges that entities may have differing protection philosophies. The drafting team believes the exchange of Protection System information is critical to the reliability of the BES; therefore, any planned changes need to follow the timetables established in the standard. In the case you cite of critical changes made during generation outages, Requirement R3, Part 3.3 allows emergency replacements to be made. Note that the requirement allows agreed upon timetables which could be significantly shorter than those noted in the standard. Based on yours and other stakeholder comments, the drafting team revised Requirement R4 separating it into two requirements, Requirements R4 and R5.		
Northeast Power Coordinating Council	No	R4 requires all affected parties agree to a solution. However, the applicable Functional Entities that PRC-027 impacts are limited only to the TO, GO and DP. When designing a protection system scheme to clear faults, a satisfactory solution in the perspective of a TO, GO and DP may have unintended consequences for the Transmission Operator. For example, what if the solution is to leave what in normal operation is a significantly loaded transmission line in a potentially open terminal configuration by leaving a ring bus configuration open after clearing a fault? How can the TO, GO and DP ensure their agreed upon solution is manageable for the Transmission Operator? There should be a notification requirement to the TOP.
Response: Thank you for your comment. The situation you describe is covered within the TOP group of Reliability Standards which cover notifications of situations that potentially pose a risk to the reliability of the BES, and is outside the scope of PRC-027-1.		
ISO RTO Council Standards Review Committee	No	R4 requires all affected parties to agree to a solution. However the applicable Functional Entities that PRC-027 impacts are limited only to the TO, GO and DP. When designing a protection system scheme to clear faults, a satisfactory solution in the prospective of a TO, GO and DP may have unintended consequences for the

Organization	Yes or No	Question 5 Comment
		Transmission Operator. For example, what if the solution is to leave a significantly loaded transmission line in a potentially single end situation by leaving a ring bus configuration open after clearing a fault? How can the TO, GO and DP ensure their agreed upon solution is manageable for the Transmission Operator? Should there be a notification requirement to the TOP?
Response: Thank you for your comment. The situation you describe is covered within the TOP group of Reliability Standards which cover notifications of situations that potentially pose a risk to the reliability of the BES, and is outside the scope of PRC-027-1.		
Essential Power, LLC	No	R4.2 can hold an entity hostage (and possibly non-compliant) if the other Interconnected Element owner does not/will not accept the proposed changes. This requirement is extremely objectionable for entities in deregulated markets, since the ?firewall? separating the regulated and deregulated sides of the business would ordinarily prevent the GO from seeing TO critical infrastructure information. R4.1 speaks of sharing only, ?summary results,? but the Application Guidelines calls on p.24 for transmittal of, ?power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings.? R4.2 also raises concerns for the situation in which a TO connects to GOs within the same corporate umbrella as well as to GOs that are part of completely separate corporate entities. The TO is legally required to treat all GOs equally, and we would certainly expect this to continue to be the case if PRC-027 is enacted, but suspicions could arise whenever expansion plans of a TO are impeded or overtly vetoed via PRC-027 ?reject? decisions by an other-corporate-entity GO and vice-versa. Proposed changes to Interconnection Service Agreements are handled under market rules, and NERC standards should not contain features that might create opportunity for infringing-on or bypassing these rules.
Response: Thank you for your comment. The drafting team acknowledges that entities may have differing protection philosophies. The drafting team believes the exchange of Protection System information is critical to the reliability of the BES. Based on yours’		

Organization	Yes or No	Question 5 Comment
and other stakeholder comments, the drafting team revised Requirement R4 separating it into two requirements, Requirements R4 and R5. The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated. Requirement R4, Part 4.1 refers to “summary results of a PSCS”. The Drafting Team agrees that a “summary” of the PSCS is appropriate. The Application Guidelines includes the broader aspect of information that may not lend itself to a “summary”, such as a schematic or a drawing. The information should be conveyed as convenient and agreed upon by both the sender and the recipient. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: “In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities.” The Standard Drafting Team agrees that contractual rights must be adhered to, including notice and approval rights. The SDT believes that the standard as drafted does not preclude those contracts, but does address instances where a contract may not address modifications. The phrase “according to an agreed upon schedule” in Requirement R4 provides an avenue to follow the terms of the contract.		
Bureau of Reclamation	No	Reclamation agrees with this comment but suggests rephrasing R4 to encourage collaboration among registered entities. Reclamation suggests that R4.1 should read ?Within 90 calendar days after receipt or according to an agreed upon schedule, review the summary results of a PSCS (per Requirement R1, R1.2) and respond to the other owner(s) by accepting the results or suggesting modifications to resolve any identified coordination.? Reclamation does not believe that entities should submit formal rejections of PSCSs merely to satisfy the standard. Reclamation suggests that the phrasing above would better encourage collaborative relay setting coordination.
Response: Thank you for your comment. The drafting team acknowledges that entities may have differing protection philosophies. The drafting team believes the exchange of Protection System information is critical to the reliability of the BES. Based on yours’ and other stakeholder comments, the drafting team revised Requirement R4 separating it into two requirements, Requirements R4 and R5.		

Organization	Yes or No	Question 5 Comment
Bonneville Power Administration	No	The requirement does not describe what further actions are required or what time limits apply if the suggested modifications are not acceptable to the originating entity.
Response: Thank you for your comment. The drafting team acknowledges that entities may have differing protection philosophies. The drafting team believes the exchange of Protection System information is critical to the reliability of the BES. The drafting team believes that any conflict resolution should be handled through normal business practices.		
Clark Public Utilities	No	The response options are agreeable, however, requirement 4 (and any sub-requirements) should not be applicable to any Interconnection Element owners that are part of the ?same Registered Entity that represents multiple functional entity responsibilities.? Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the same organization that developed the Protection System Coordination Study to provide a document accepting it or rejecting it. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of ?Separate Registered Entities and ?Same Registered Entities? it is suggested that the wording be modified to incorporate theses terms as follows:R4. Each Transmission Owner, Generator Owner, and Distribution Provider that is a Separate Registered Entity and each Same Registered Entity (on behalf of its multiple functional entity responsibilities) shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]4.1. Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a PSCS (per Requirement R1, Part 1.2) and respond to the Registered Entity providing the PSCS:? Accepting the results, or? Rejecting the results and suggesting modifications to resolve any identified coordination issues.4.2. Prior to implementing any proposed change(s) or modifications associated with Requirement

Organization	Yes or No	Question 5 Comment
		R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other Separate Registered Entities that are owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.
Response: Thank you for your comment. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."		
Southwest Power Pool	No	The way the requirement is currently worded, the sending entity could conceivably be found non-compliant if an entity receiving the results does not respond within 90 days. We would suggest incorporating language to clarify that the receiving entity has the obligation to respond within 90 days. This could be accomplished by inserting ?each recipient of the results shall? in the requirement. The requirement would then read ?Within 90 calendar days after receipt, or according to an agreed upon schedule, each recipient of the results shall review the summary results of a PSCS??
Response: Thank you for your comment. The role of the drafting team is to draft a standard that minimizes the probability that an auditor could misinterpret the intent of the standard's requirements. The drafting team has expressed to NERC staff the desire to participate in the development of the RSAW. The entity not responding in a timely manner may be in violation of Requirement R4. Based on yours and other stakeholder comments, the drafting team revised Requirement R4 separating it into two requirements, Requirements R4 and R5.		
DTE Electric	Yes	None
City of Tacoma	Yes	Should the Flowchart be updated to reflect the course of action if an entity rejects the results and suggests modifications to resolve any identified coordination issues?
Response: Thank you for your support. The drafting team revised the flow chart to be consistent.		

Organization	Yes or No	Question 5 Comment
FirstEnergy Corp	Yes	We agree with Part 4.1 of Requirement 4, but we have comments regarding Part 4.2 and have stated below in Question 8.
Response: Thank you for your support.		
Duke Energy	Yes	
Dominion	Yes	
Madison Gas and Electric Company	Yes	
Associated Electric Cooperative, Inc.	Yes	
SERC RRO	Yes	
JEA	Yes	
PacifiCorp	Yes	
Electric Reliabilty Compliance	Yes	
PJM Interconnection	Yes	
Southern Company	Yes	
Dynegy	Yes	
Exelon and its Affiliates	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 5 Comment
Independent Electricity System Operator	Yes	
Ingleside Cogeneration LP	Yes	
Texas Reliability Entity	Yes	
American Electric Power	Yes	
ITC	Yes	
Public Service Enterprise Group	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	
Ameren	Yes	
Kansas City Power and Light	Yes	
SMUD	Yes	
NextEra Energy	Yes	
Xcel Energy	Yes	
Illinois Municipal Electric Agency	Yes	
California ISO		See associated SRC Comments

Organization	Yes or No	Question 5 Comment
Response: Please refer to the SRC comments.		

6. **The drafting team revised the Applicability section of PRC-001-2 to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.) Do you agree with this revision to the Applicability? If not, please provide specific suggestions for improvement in the comment area.**

Summary Consideration:

The drafting team appreciates your comments regarding PRC-001. After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PER-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.

Organization	Yes or No	Question 6 Comment
American Electric Power	No	AEP appreciates the drafting team?s efforts to clearly identify the Protection Systems that are applicable to Requirement R1 but is concerned that the combination of Applicable Facilities in Section 4.2 and Requirement R1 may result in burdensome training requirements for the TOP, BA and GOP that do not provide an increase to BES reliability. In particular, the Applicable Facilities includes Protection Systems installed for the Generator Step-Up transformers, Station Service transformers and the Excitation transformers. Nowhere does the standard limit the scope of this applicability to a subset of the Applicable Functional Entities. As a result, an auditor may interpret the standard to require that the TOP and BA be familiar with this level of generator protection for the units connected to their system.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments		

Organization	Yes or No	Question 6 Comment
section above.		
Bonneville Power Administration	No	As described in the Facilities Section, the protection systems for which the requirements are applicable are ?Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements?. Since most Protection Systems are capable of isolating faulted elements without coordination, nearly all Protection Systems would be exempt from the requirements. While this would be acceptable to us, we don?t think this is what the drafting team intends.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Public Service Enterprise Group	No	Change section 4.2.1 (capitalized words show changes) as follows: ?4.2.1 - Protection Systems that are installed for the purpose of detecting AND ISOLATING Faults on BES Elements (lines, buses, transformers, etc.)?
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
LG&E and KU Services	No	Did you mean PRC-001-3? If so, the response is, ?Yes.?
Response: Thank you for your comment. The drafting team did mean PRC-001-3. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Flathead Electric Cooperative, Inc.	No	Do not believe that a DP-only entity would typically have Interconnected Elements that would necessitate inclusion, when the purpose is to protect the TO equipment.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		

Organization	Yes or No	Question 6 Comment
Bureau of Reclamation	No	Reclamation requests that the drafting team clarify which Protection Systems ?require coordination? for isolating faulted Elements, or remove the phrase ?that require coordination? from the definition of Facilities.
Response: Thank you for your comment. Your comment is apparently referencing the Facilities section of PRC-027-1 and does not pertain to this question.		
City of Tacoma	No	The level of detail in the Applicability section appears to be inconsistent with the language in M1 ??training in basic relaying?? For this reason, it is recommended not to include the ?Facilities? portion.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Independent Electricity System Operator	No	We do not have any comment on the revised Applicability Section, but continue to express a serious concern with leaving PRC-001 in its present form. As indicated in our previous comment, we do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. This is a training requirement and as such, it should be transferred to the appropriate PER standards. Providing training evidence does not demonstrate that the (operating personnel of) responsible entities are ?familiar with? the purpose and limitations of protection system schemes applied in its area. c. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. In response to our previous comment, the SDT indicates that it

Organization	Yes or No	Question 6 Comment
		??recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.? We do not agree with this recommendation and hold the view that adding the issue to the NERC Issue Data Base is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT should propose a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee?s advice/direction for appropriate actions. We do not believe that the SDT or staff has brought this to the Standards Committee?s attention. Note that the Standards Committee is responsible for managing the standards development process and as such, can make an informed decision to either request the SDT to expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel. Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. Once again, we urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Manitoba Hydro	Yes	(1) The title of the new PRC-001-3 standard does not seem to be the appropriate title since the standard addresses protection coordination issues, rather than requiring the system operators to be familiar with, and understand the protection system.
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments		

Organization	Yes or No	Question 6 Comment
section above.		
Duke Energy	Yes	Duke Energy believes that the Facilities section provides sufficient detail and clarity for this standard.
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Ingleside Cogeneration LP	Yes	ICLP agrees that consistency between NERC standards is helpful. Since our Protection System maintenance program has been developed specifically to address BES relaying, it is a straight forward process to develop the related Operator training.
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments section above.		
ITC	Yes	ITC Holding is in agreement with the clarification on which protection systems are applicable to requirement 1. Using the same definition as used in PRC-005-2 promotes consistency across the standards within the same category (PRC).
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments section above.		
DTE Electric	Yes	None
PacifiCorp	Yes	PacifiCorp would like to highlight a recommendation that was made by the drafting team on page 4 of Draft 3 of PRC-027-1 regarding Requirement R1 of PRC-001-2. The drafting team has recommended via the NERC Issues Database that the future standards drafting team tasked with revising PER-005-1 incorporate the reliability objective of PRC-001-2 Requirement R1 into that revised standard. PacifiCorp is concerned with the potential overlap that could result from the failure to retire Requirement R1 in PRC-001-2 concurrent with the effective date of the new version of PER-005. To avoid the risk of entities having to comply with duplicative

Organization	Yes or No	Question 6 Comment
		requirements under two currently-effective standards, the standards drafting team should include language in PRC-001-2 expressly confirming that compliance with the relevant requirement of the revised version of PER-005 will satisfy Requirement R1 of PRC-001-2 until such requirement is retired. In addition, there have been several proposals in the informal development of PER-005-1 that would expand the scope of applicability to include Generator Operators and Support Personnel. If R1 of PRC-001-2 is to be included in the new version of PER-005-1, the requirements of R1 could apply to additional functional entities. As such, any recommendation to move R1 of PRC-001-2 into the new version of PER-005-1 should be part of the PER-005-1 discussions that are currently taking place. At present, they are not. PacifiCorp would like to encourage more collaboration between drafting teams on the development of new draft standards and would like to thank the System Protection Coordination Standard Drafting Team for highlighting this recommendation.
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments section above.		
SERC RRO	Yes	Regarding the applicability to the Generator Operator, the registered function of the Generator Operator could exist as a centralized corporate function as well as a remote function at the generation station. The requirements are probably aimed at the remote function, but if the corporate function embodies an electrical design group that is ?familiar? with the protection systems ?in their area?, is that sufficient for compliance? The draft includes a description of applicable ?Facilities?, but the question still applies.
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Northeast Power Coordinating Council	Yes	There should be consistency between standards on this point.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Florida Municipal Power	Yes	
ISO RTO Council Standards Review Committee	Yes	
Pepco Holdings	Yes	
FirstEnergy Corp	Yes	
Dominion	Yes	
Madison Gas and Electric Company	Yes	
Associated Electric Cooperative, Inc.	Yes	
Southwest Power Pool	Yes	
Cooper Compliance Corp	Yes	
JEA	Yes	
Electric Reliabilty Compliance	Yes	
Southern Company	Yes	
Dynegy	Yes	

Organization	Yes or No	Question 6 Comment
Exelon and its Affiliates	Yes	
Texas Reliability Entity	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	
Ameren	Yes	
Kansas City Power and Light	Yes	
Clark Public Utilities	Yes	
NextEra Energy	Yes	
Xcel Energy	Yes	
Essential Power, LLC		Did you mean PRC-001-3? If so, the response is, ?Yes.? We believe however that PRC-001 should be left as-is and PRC-027 should be made an exclusively TO-applicable standard, as explained elsewhere in these comments.
Response: Thank you for your support. The drafting team did mean PRC-001-3. Please see statement related to the future of PRC-001 in the summary of comments section above.		
California ISO		See associated SRC Comments
Response: See response to the SRC comments.		

7. **The drafting team provided a measure to accompany Requirement R1 of PRC-001-2. (The language in the measure was modeled after the existing language in the RSAW for PRC-001-2.) Do you agree with this measure? If not, please provide specific suggestions for improvement in the comment area.**

Summary Consideration:

The drafting team appreciates your comments regarding PRC-001. After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PRC-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.

Organization	Yes or No	Question 7 Comment
Public Service Enterprise Group	No	? Requirement R1 requires that ?Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.? This is too broad and vague with respect to which TOP, BA and GOP personnel are in the requirement?s scope. Subject to addressing PSEG?s additional comment of ?What is meant by ?familiar with? in R1?? in the bullet below, PSEG recommends that the requirement at least be revised to: ?Transmission Operator, Balancing Authority, and Generator Operator personnel shall be familiar with the basic purpose and limitations of protection system schemes applied to the BES equipment and Facilities they control.?? M1 should describe methods other than documented training to meet R1 ? see the ?but not limited to? language. What is an alternative to documented training? What is meant by ?familiar with? in R1? Until ?familiar with? is better defined, M1 cannot be

Organization	Yes or No	Question 7 Comment
		written.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Essential Power, LLC	No	a. Did you mean PRC-001-3? b. It is not necessary to separate "limitations" from "purpose" in the VSL, and recommend that a single Severe VSL be used to cover all of R1 by using the requirement R1 verbiage "?familiar with the purpose and limitations of ?" PRC-001 moreover should remain as is, with PRC-027 being applicable to GOs under only very limited circumstances, as stated above. c. The word ?area? in R1 of PRC-001-3 needs to be defined for compliance to be measured and enforced. The area for GOs should be restricted to the plants they own, if PRC-001 is modified (see other comments).
Response: Thank you for your comment. The drafting team did mean PRC-001-3. Please see statement related to the future of PRC-001 in the summary of comments section above.		
LG&E and KU Services	No	a. Did you mean PRC-001-3? b. The word ?area? in R1 of PRC-001-3 needs to be defined for compliance to be measured and enforced. The area for GOs should be restricted to the plants they own, if PRC-001 is modified (see other comments).
Response: Thank you for your comment. The drafting team did mean PRC-001-3. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Ingleside Cogeneration LP	No	ICLP believes that the measure should identify that front-line operators are the target audience of the training. As a Generator Operator, we employ engineers, process developers, and operators ? and not all of these individuals require basic Protection System training. This ambiguity should be resolved while there is focus

Organization	Yes or No	Question 7 Comment
		on PRC-001.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Xcel Energy	No	Since there are no guidelines on who ?applicable personnel? are, and there are no guidelines on what type of training is required and how often, this measure serves little purpose should be removed. Measures and VSLs are overly complex and will be difficult to effectively track as written.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
American Electric Power	No	The examples of evidence in Measure M1 appear to be overly simplistic compared to the potential scope of R1.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Northeast Power Coordinating Council	No	To specifically address Requirement R1, the Measure should be rewritten to stress that there be familiarity with the protection system schemes applied in its area. Suggest revising the Measure for Requirement R1 to read: Each Transmission Operator, Balancing Authority, and generator Operator shall have evidence that its appropriate personnel were made familiar with protection systems in its area. That can be made easily auditable by having written summaries of the schemes, and have personnel sign offs after reading.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		

Organization	Yes or No	Question 7 Comment
Tri-State G &T	No	Tri-State believes that the Requirement R1 and Measure M1 need to refer more directly to the Facilities included in the Applicability section. A couple of options are presented below. Option 1: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of the following protection system schemes applied in its area: • Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.) • Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements. • Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability. • Protection Systems installed as a Special Protection System (SPS) for BES reliability. • Protection Systems for generator Facilities that are part of the BES, including: o Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays. o Protection Systems for generator step-up transformers for generators that are part of the BES. o 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). o 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.

Organization	Yes or No	Question 7 Comment
		If Option 1 is chosen, then the Facilities section in the Applicability can be removed. Option 2: M1. For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in the purpose and limitations of the Protection System schemes included in the Facilities section of the Applicability that are used within its area was provided to its applicable personnel.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Independent Electricity System Operator	No	We do not agree with the proposed Measure for the reason as stated under Q6, above.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Southern Company	No	While we agree with the changes made to the applicability section and the measurement section, we believe that it is not necessary to separate "limitations" from "purpose" in the VSL, and recommend that a single Severe VSL be used to cover all of R1 by using the requirement R1 verbiage "?familiar with the purpose and limitations of ?". Will compliance be evidenced by training records for individuals, the content of the training, or both? How might the "familiar with limitations" and "familiar with purpose" be separately evaluated in an audit?
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
SERC RRO	Yes	The requirement still calls for ?familiarity? with the protection systems ?in their area?. The extent of ?familiarity? comes into question as well as the question of

Organization	Yes or No	Question 7 Comment
		what constitutes ?their area?. The newly crafted Measurement attempts to give some detail as to what that means. But if training is the expected means of achieving compliance, why not just require the training? And if training is expected, then the scope of that training should be related to application of a systematic approach to training, not a scope identified by the SDT, or an area arbitrarily selected by the auditors.
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Ameren	Yes	(1) The measure was provided for PRC-001-3, not PRC-001-2.
Response: Thank you for your support. The drafting team did mean PRC-001-3. Please see statement related to the future of PRC-001 in the summary of comments section above.		
FirstEnergy Corp	Yes	Although we agree with the proposed change, we have reservations of having a standard with only 1 requirement. Please see our comments on Question #8.
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Dominion	Yes	Dominion believes the reference to PRC-001-2 is incorrect and should be noted as PRC-001-3 as PRC-001-2, Page 11, cites ?Measures and Compliance Elements will be added to a later draft.? Dominion supports the measure accompanying Requirement 1, as included in PRC-001-3. Dominion also notes that the reference to the RSAW for PRC-001-2 is incorrect and should reference the RSAW for PRC-001-1.Dominon was unable to locate a draft of RSAW PRC-001-2 or PRC-001-3 on the Standards Under Development NERC webpage or under any category, on the NERC RSAW page.
Response: Thank you for your support. The drafting team did mean PRC-001-3. Please see statement related to the future of PRC-		

Organization	Yes or No	Question 7 Comment
001 in the summary of comments section above.		
ITC	Yes	ITC Holdings is in agreement to add the measure to the standard to be in-line with the language in the RSAW for PRC-001-2.
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments section above.		
DTE Electric	Yes	None
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Bureau of Reclamation	Yes	Reclamation thanks the drafting team for assisting Registered Entities with the transition from PRC 001 to PRC-027 by incorporating the RSAW language to ensure continuity of compliance.
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Southwest Power Pool	Yes	While we concur with the proposed measure, there does appear to be a mismatch between the requirement and the measure. See our comment in Question 8 below to address this issue.
Response: Thank you for your support. Please see statement related to the future of PRC-001 in the summary of comments section above.		
Florida Municipal Power	Yes	
ISO RTO Council Standards Review Committee	Yes	

Organization	Yes or No	Question 7 Comment
Pepco Holdings	Yes	
Duke Energy	Yes	
Bonneville Power Administration	Yes	
Madison Gas and Electric Company	Yes	
Associated Electric Cooperative, Inc.	Yes	
Cooper Compliance Corp	Yes	
JEA	Yes	
City of Tacoma	Yes	
PacifiCorp	Yes	
Electric Reliabilty Compliance	Yes	
Dynegy	Yes	
Exelon and its Affiliates	Yes	
Manitoba Hydro	Yes	
Texas Reliability Entity	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 7 Comment
Idaho Power Co.	Yes	
Kansas City Power and Light	Yes	
Clark Public Utilities	Yes	
SMUD	Yes	
NextEra Energy	Yes	
California ISO		See associated SRC Comments

8. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Summary Consideration:

Many commenters had concerns about PRC-001-3. The drafting team responded that the PRC-001 standard is planned to be retired.

Some commenters suggested minor grammatical, style and formatting changes. The drafting team made the appropriate changes.

Various commenters suggested minor revisions to the standard that were accepted by the drafting team as follows:

the word "demonstrates" was replaced with "documents" in the definition of the PSCS.

the Facilities section of the Applicability was simplified by eliminating section 4.2.1., it now reads as follows:

Facilities:

Protection Systems: a) installed for the purpose of detecting Faults on Interconnecting Elements, and; b) that require coordination for isolating those faulted Elements.

updates to the descriptions of the referenced standards and other minor revisions made in the Background section.

the word "permanent" was added to Requirement R3, Part 3.3.

the phrase "associated with the Interconnecting Element" was added to Requirement R3, Part 3.3.

the word "modification" was replaced with "addition" in Requirement R4, Part 4.2 (now Requirement R5) and Measure 10 (now Measure 9) to be consistent with Requirement R3, Part 3.1.

Figures 3 and 4 were revised to indicate the tap line is the Interconnecting Element.

Some commenters believed the standard should not apply to separate functional entities within the same registered entity. The response indicated that the drafting team does not agree because they are cases where the Transmission Owner and Generator Owner are part of the same Registered Entity but separate technical groups are involved in performing the required Protection System Coordination Studies. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."

Other commenters suggested changes that were not included in the revised standard as follows:

wanted only one Measure per Requirement. The drafting team followed the Drafting Team Guidelines by developing at least one Measure for each Requirement. The guidelines do not prohibit multiple measures per requirement.

the 10% threshold was too small because fault duties vary widely depending on operating conditions. The drafting team explained the threshold of 10% was selected based on experience of drafting team members, discussion with members of various regional protection and control committees, and the recognition that there are margins of error in models and in protection system accuracies.

wanted more specific guidance and methodology for the performance of the PSCS. The drafting team explained that it specified minimum requirements but allowed flexibility in the performance of the PSCS.

wanted some types of changes to Protection Systems that they consider inconsequential not to need to be reported. The drafting team indicated that any change that modifies a condition used in the coordination of Protection Systems needs to be communicated to the other owner(s).

concerns surrounding coordination between DP and TO (see Duke) Because there are no Protection Systems at Breaker C that protect for Faults on BES Elements, the subject Protection Systems are not applicable under this standard. The drafting team understands the commenter's point; however, this standard only applies to Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements.

Organization	Question 8 Comment
LG&E and KU Services	a. PRC-027-1, R3.3 should be limited to Protection Systems associated with Interconnected Elements b. There is no clear indication of need to change the present system. The SDT states on p.21 of PRC-027 that ?[t]he drafting team has no evidence there is widespread miscoordination between Owners of Facilities,? and ?records collected for reliability standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.? The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027

Organization	Question 8 Comment
	back into PRC-001. c. Please retain one measure per requirement so that the Measurement numbers in PRC-027-1 match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts.
Response: Thank you for your comments. **a. The drafting team made the suggested change to Requirement R3, Part R3.3.** **b. The drafting team discussed your suggestions and determined that your recommended changes are not feasible.** **c. The drafting team followed the Drafting Team Guidelines by developing at least one Measure for each Requirement. The guidelines do not prohibit multiple measures per requirement.**	
Seminole Electric Cooperative Inc.	(1) In proposed PRC-027-1 R2, Seminole believes that the Reliability Coordinator (RC) should have the responsibility of performing any studies or analyses and the distribution of those studies/analyses required under R2 instead of the Transmission Owner (TO). In peninsular Florida, the RC has access to the data needed for the analyses and having a single entity perform the analyses and distribution will assure uniformity across the region. (2) In proposed PRC-027-1 R2-2.2.1., Seminole believes the 10% threshold for fault current is too low, as this percent change occurs daily. Seminole recommends the 10% threshold value be increased to 20% for fault current. (3) In proposed PRC-027-1 R2, is the 10% change in fault current study based on the individual TO?s system contribution as an island at the interconnection bus, or does it include all other interconnection that border the TO?s system that could provide fault current, i.e., how many buses out from the TO?s other interconnections does the study require for determining available fault current? (4) In proposed PRC-027-1 R2, Seminole believes that the requirements and guidelines for the Protection System Coordination Study (PSCS) need to be more specific and give additional detailed methodology.

Organization	Question 8 Comment
	(5) In proposed PRC-027-1 R3-3.1, it should be noted that current and voltage ratio changes do not necessarily indicate a change in the protection system if the protective relay set points are adjusted accordingly. Therefore, R3-3.1 should be revised to reflect that certain ratio changes do not require notification.
Response: Thank you for your comments. (1) The Functional Model assigns real-time operating responsibilities to the Reliability Coordinator, and the requirement in PRC-027-1 are planning horizon. The drafting team has assigned the responsibility of performing the short circuit studies in Requirement R2 to the Transmission Owner because the TO has all the data required to run the studies. (2) The threshold of 10% was selected based on experience of drafting team members, discussion with members of various regional protection and control committees, and the recognition that there are margins of error in models and in protection system accuracies. The Application Guidelines indicate that the short circuit studies performed for this function typically assume maximum generation and all Facilities in service. The drafting team believes that this value will not change daily. No change made to the standard. (3) The 10% change is based on the total Fault current available at the interconnecting bus. (4) The drafting team believes the Application Guidelines provide sufficient guidance on the methodology of the PSCS and intentionally allowed flexibility for the entities to comply with the standard. No change made to the standard. (5) The drafting team believes that any transformer ratio change that modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s) need to be provided to the other entities associated with the Interconnecting Element(s). No change made to the standard.	
Manitoba Hydro	(1) The wordings of the sentence ?Examples of Protection Systems where technical justifications may be used include? under heading ?Requirement R2 in the ?Application Guidelines? are unclear. MH suggests that It read as follows: ?Examples of Protection Systems that are not affected by the fault current change include?.Also, under the same section, it?s very confusing as to what relays the following refers to:4. Reverse power, definite time &/or time overcurrent elements: Designed to coordinate during maximum generation with the transmission system under normal operating conditions and includes the calculation of the percent deviation between the under single contingency conditions regardless of Fault current. Designed for the protection of equipment other than for the

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	purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.). (2) Protection System Coordination Study definition - for clarity, replace the word ?that? with the word ?which? and insert the word ?that? between ?demonstrates existing?. Moreover, consider replacing the words ?for clearing Faults? with ?during Faults? for consistency with the purpose of the Standard. The suggested definition should read ?A study which demonstrates that existing or proposed Protection Systems operate in the desired sequence during Faults. This definition should also be changed in the rational for R1 section and Implementation Plan document if it is an accepted change by the SDT. (3) Background - references are made to standards PRC-001, PRC-027, TOP-003, PRC-005, etc. in this section, which in some cases, do not include the title following the standard number. For consistency, the title should be included, or in the least referred to at the first instance of the standard number in this section. (4) Other Aspects of Coordination of Protection Systems Addressed by Other Projects - replace the period ?.? at the end of the last paragraph with a colon ?:? .Moreover, follow each project number with its title for consistency and clarity. (5) R1.2 - the words ?Protection Systems? and ?Currents used? should be written as ?Protection System(s)? and ?Current(s) used? to maintain consistency with the rest of the paragraph.As a note, consider changing all instances of the words ?Protection Systems?, ?Currents?, ?owners? and ?Interconnected Elements? to ?Protection System(s)?, ?Current(s)?, ?owner(s)? and ?Interconnected Element(s)?, to maintain consistency throughout the document. (6) R2.1 - remove the words ?Protection System Coordination Study?, leaving only the acronym ?PSCS?, because it has been previously defined in the document. (7) R2.2.1 and M5 - add an ?s? or ?(s)? to both ?Protection System? and ?Interconnected Element?.

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	(8) M4 - replace ?is? with ?includes? and ?that contains? with ?which contain?. (9) All measures - for consistency, the phrase ?may include, but is not limited to,? should be added to each measure. (10) R4.2 - place brackets around the ?s? in the following words ?modifications? and ?issues? for consistency with the rest of the document. Please continue this change throughout the Standard and Technical Guideline document for consistency. (11) 1.2 Evidence Retention - is it necessary to state that ?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.? since this information is already included in the CMEP. (12) R4.2 and M10 - the words ?proposed changes and modifications? should be changed to ?proposed changes and additions? to mirror the wording in R3.1.

Response: Thank you for your comments.

(1) The drafting team believes the wording is consistent with the requirement and is not confusing. The conditions described in each of the bullets apply to any of the relays listed. No change made to the standard.
(2) The drafting believes that the proposed definition is both technically and grammatically correct. No change made to the standard.
(3) The drafting team believes that the standard number is all that is required to adequately reference other standards in the Background section. No change made to the standard.
(4) The drafting team has made the suggested changes.
(5) The drafting team has made the suggested changes to Requirement R1, Part 1.2.
(6) The drafting team has made the suggested changes.
(7) The drafting team has made the suggested changes.
(8) The drafting team believes that M4 is accurate and grammatically correct as proposed. No change made to the standard.
(9) The drafting team included "may include, but is not limited to" only in instances where it believed the phrase was

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	appropriate. No change made to the standard. **(10) The drafting team moved the content of Requirement 4, Part 4.2 to Requirement 5, and your suggested changes were made.** **(11) ????????????????** **(12) The drafting team moved the content of Requirement 4, Part 4.2 to Requirement 5, and your suggested changes were made.**
Ameren	(1) In Application Guidelines for R1, please add ?A Protection System Coordination Study includes, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed.? We request adding it just after the definition of a PSCS. This will more clearly align the Application Guidance with R1.2. (2) Under Requirement 2, studies are referred to as ?most recent? and ?present? which is confusing and could be considered synonymous. We ask the SDT to change this terminology to replace ?most recent? with ?previous? study and ?present? with ?new? study in all places within the standard where they exist. (3) Requirement R3, 3.1 first bullet is both broad (new installation, replacement with different types) and specific (modifications to protective relays or protection functions settings, communications, CT/PT ratios). The 3.1 text itself clearly targets changes or additions to existing or new Facilities that modify conditions that impact coordination of Protection Systems. We request the SDT to replace the existing bullet points to clarify areas of this emphasis to these bullet points:?? Change in Protective Relay Types or Functions? Change in Communication System(s) that interface with Protection System(s)? Change in connected voltage (VT) or current (CT) source ratios? Change to transmission system Element(s) that alters impedance? Change to generator unit (s) that alters impedance, or? Change to generator step-up transformer (s) that alter in impedance? (4) We request the SDT to clarify 4.2 by combining 4.2.1 into it, thus removing the separate 4.2.1. Please reword as follows: ?These requirements contained herein are applicable to each 4.1 Functional Entity that owns Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require

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	coordination for isolating those faulted Elements.?

Response: Thank you for your comments.

1. **The Application Guidelines for Requirement R1, Part 1.2 already do indicate what minimum information must be included in the PSCS, and give more detail rather than reiterating the language in the standard. No change made to the standard.**
2. **The drafting team used "present" to qualify the short circuit study and "most recent" to qualify the Protection System Coordination Study, which are two different studies. It is only when the difference between the values in the two types of studies exceeds 10% does a new Protection System Coordination Study need to be performed. No change made to the standard.**
3. **The first bullet refers to any changes made to the Protection System(s) and the drafting team did not believe it was necessary to individually bullet each component, whereas the other bulleted items refer to different types of changes that could change the impedance in the system. No change made to the standard.**
4. **Based on yours and others' comments, the drafting team revised the Applicability section to remove 4.2.1.**

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Southern Company	(a) The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027 back into PRC-001. (b) Please retain one measure per requirement so that the Measurement numbers match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts. (c) There is no equation found in R2.2. (d) In R3.3, it is not clear when the 30 days starts - is it the 30 days following the change(s)? (e) R3.3 should be limited to Protection Systems associated with Interconnected Elements. (f) 4.2 can hold an entity hostage if the other Interconnected Element owner does not/will not accept/reject the changes.

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Response: Thank you for your comments. **(a) The drafting team discussed your suggestions and determined that your recommended changes are not feasible.** **(b) The drafting team followed the Drafting Team Guidelines by developing at least one Measure for each Requirement. The guidelines do not prohibit multiple measures per requirement.** **(c) The equation was initially missing in the posted version due to formatting errors that occurred during the posting process. The corrected standard was posted on the NERC web site on June 21, 2013.** **(d) The drafting team modified the language for clarity. Yes, within 30-days of making the change is correct.** **(e) The drafting team made the suggested change to Requirement R3, Part R3.3.** **(f) The content of Requirement R4, Part 4.2 was moved to Requirement R5. The drafting team believes that any conflict resolution should be handled through normal business practices.**	
Pepco Holdings	1) The SDT states that ?the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays?. However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. The mention of ?the appropriate use of time delays in relays? in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped (exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. The solution was not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. Similarly in the

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	recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS?s during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue. As such, although PHI supports the overall desire to ensure that protective systems are ?properly coordinated?; PHI sees little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1 stated that they have no evidence that there is widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry. The above comment was also submitted with Draft 1 of the standard. In their response the SDT stated that PRC-027 was being developed in response to FERC Order 693. However, Order 693 only directs NERC to address specific deficiencies in PRC-001 surrounding certain measures and levels of non-compliance relating to the notification and response to the detection of failures in relay protection systems. As such, PHI believes PRC-027 goes well beyond what is was directed by FERC, and the stated purpose of the SAR. PHI urges the SDT to revisit FERC Order 693 and revise this standard as appropriate to address only the stated FERC directives. 2) Based on the arguments presented in the above comments, including the lack of historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions, PHI suggests that NERC conduct a Cost Effective Analysis (CEA) to provide information about cost impacts (e.g., implementation and ongoing compliance resource requirements) of this draft standard and its relative effectiveness in preventing

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	widespread blackouts, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of this standard. 3) Requirement R2, Parts 2.1.1 and 2.1.2: Remove the term ?interconnecting bus? and replace it with the phrase ?point of interconnection between the Entities.? The point of interconnection between the entities is more descriptive in that the interconnection point may not be a physical ?bus?, but rather the terminals of a line disconnect switch, terminals of a breaker, specific transmission pole, etc. Even though the point of interconnection is often modeled in a short circuit program as a ?bus?, the term ?interconnecting bus? has no physical meaning. 4) Requirement R3, Part 3.3: A footnote should be added stating that this requirement does not apply to those temporary setting changes that sometimes are applied during commissioning, maintenance, or investigative testing activities to verify performance of individual protective elements, provided the original settings were returned upon the conclusion of the testing activity. For example, in multifunction relays when testing backup time delayed protective elements (i.e., zone distance or time overcurrent elements) it may be necessary to temporarily disable high speed elements (i.e., pilot or zone 1 elements). In response to this comment the SDT responded that it ?believes temporary settings changes are addressed in TOP-002, which incorporated Requirements R5 and R6 from PRC-001-1. Temporary settings applied (or changed) to perform maintenance testing of a relay would not have an effect upon overall coordination of the Protection System, as the relay would likely be taken out of service for such testing.? PHI agrees with this conclusion, however, this standard does not specifically exclude these temporary changes from Part 3.3. Therefore an auditor may conclude that they are in scope for this standard. As such, PHI suggests Part 3.3 be qualified with a footnote to specifically exclude these types of temporary settings. 5) Based on the commentary accompanying Figure 3 in the Guidelines and Technical Basis document it appears that a Protective System Coordination Study (PSCS) is required only if there are protective systems installed on breaker C for the purpose of detecting faults on the BES system. Is there a recommended criteria or generation size below

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	which there is no need for a PSCS, or for a dedicated ?fault protection system? at Breaker C to detect faults on the Interconnected BES element? For example, suppose all generation downstream of the Distribution Provider?s system is comprised of solar installations with non-islandizing inverters. In these cases, it would be unusual to install fault detection systems ?looking into? the BES system at breaker C even though there is generation installed downstream. The non-islanding inverters with 27/59 and 81O/U protection would isolate the generation upon loss of transmission source when Breakers A and B opened. Similarly, if a small synchronous generator was installed on a downstream distribution feeder with sufficient connected load to ?swamp? the generator upon the loss of transmission source, protective relays at the generator location, rather than at Breaker C, would operate to remove the generator upon loss of the transmission system source. In both of these examples, even though there may be overcurrent protection, or fuses, installed on the high side of the transformer for transformer faults, there is no dedicated fault protection system installed at breaker C for the purpose of detecting faults on the transmission system, and as such there would be no need for a PSCS. Is this correct?
Response: Thank you for your comments. **1) The reference to Recommendation 21C has been removed from the standard.** **2) The drafting team will forward your recommendation to NERC staff.** **3) The drafting team believes that the diagrams in the Application Guidelines clearly define the term "interconnecting bus."** **4) The drafting team added the word "permanent" to Requirement R3, Part 3.3 to address your comment.** **5) The drafting team intended Figure 3 to be interpreted as you suggest.**	
Xcel Energy	1) PRC-027-1 R3.2 has a deadline based on the date of receiving a request. There should more details regarding what constitutes receiving a request. If informal channels are used, there may be disagreement about whether the 30 day deadline was met.The complexity of this standard becomes all the more evident when looking at ways to implement and track all the measures. For many of the measures, the only practical way to capture time frames is to tie communications with an interconnected entity to a task

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	within an established schedule. Communications with interconnected entities will likely need to become more limited and formal to become more trackable. Bringing tractability to emails and other communications for evidence will be a significant issue, with the need to capture communications of out-side resources performing studies as well as the use of secure email requiring tedious offloading or screen captures of communications from secure servers. It would be recommended that acceptable evidence demonstrating the time frames should allow for documented processes along with activity schedules providing start and completion dates. More detailed evidence should be signed and verified studies, which indicate that validated models and remote settings have been utilized in the analysis. Here are our specific recommendations by requirement and measure: a) Requirement R1- R1.1.3- It would be recommended to be consistent with the time frame as specified in 1.1.2 and change the specified calendar months to read ?or within 12 calendar months of being notified of a change as described in Requirement R3, Part 3.3.? M1, M2 - Acceptable evidence demonstrating time frames should allow for documented processes along with activity schedules providing start and completion dates. (VSL) Violation Security Levels- Each security level should provide consistent time frames to avoid confusion in tracking. b) Requirement R2 ?R2.2- Allowance should be made to allow for tracking of fault level trends at the bus based on a 10% change in fault level for the year of the coordination study. M5 - Acceptable evidence demonstrating time frames should allow for documented processes along with activity schedules providing start and completion dates.(VSL) Violation Security Levels- Each security level should provide consistent time frames to avoid confusion in tracking. c) Requirement R3 ?M7 ? A data request should indicate that it is being made per requirement R3 of PRC-027 to be measured under M7. M6, M7, M8- Acceptable evidence demonstrating time frames should allow for documented processes along with activity schedules providing start and completion dates. d) Requirement R4?R4- Study submittals should be required to stipulate that the study is

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	being submitted per requirement R4 of PRC-027 to be measured under M9. M9, M10- Acceptable evidence demonstrating that the time frames have been met should allow for documented processes along with activity schedules providing start and completion dates. 2) 4.2.1 Applicability: For Generator Owners, many elements that are covered under the PRC-019, PRC-024 and PRC-025 (and future Phase 3 Loadability Standards) also fall under the Facilities Section of this draft of PRC-027-1, as the functions exist for the sole purpose of allowing coordination for faults to clear external to the generator. The elements covered by other standards should be excluded from applicability, in order to avoid a double jeopardy situation.Instead, we recommend that a list of applicable elements be identified. Typical functions are identified below. We believe these to be the only functions applicable to the standard as far as a GO is concerned.- Ground Time Overcurrent Relay ? (Directional Towards the System) (51G) - Neutral Time Overcurrent Relay ? (Directional Towards the System) (51N) - Ground Directional Time Overcurrent Relay ? Directional Toward Transmission System (67G) - Negative Phase Sequence Overcurrent (46) In addition, please consider adding a list of excluded elements, such as these:- Phase Distance (21) (Covered under PRC-025) - Volts/Hz (24) (Covered under PRC-024) - Undervoltage (27) (Covered under PRC-024) - Reverse Power (32) (Not applicable to standards as it is protection for the generator) - Loss of Field (40) (Covered under PRC-019) - Inadvertent Energization (50/27) (Not applicable to standards as it is protection for the generator) - Breaker Failure (50BF) (Not applicable to standards as it is protection for the generator) - Phase Time Overcurrent Relay (51) (Covered under PRC-025) - Phase Time Overcurrent Relay ? Voltage-Restrained (51V-R) (Covered under PRC-025) - Phase Time Overcurrent Relay ? Voltage Controlled (51V-C) (Covered under PRC-025) - Overvoltage (59) (Covered under PRC-024) - Field Overvoltage (59E) (Covered under PRC-019) - Stator Ground (59GN/27TH/64S) (Not applicable to standards as it is protection for the generator) - Field Ground (64F) (Not applicable to standards as it is protection for the generator) - Phase Directional Time Overcurrent Relay ? Directional Toward Transmission System (67) (Covered under PRC-025) - Field Overcurrent (76E) (Covered under PRC-019) - Out of Step (78) (Covered under Future Phase 3 Loadability Standards) - Frequency (81)

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	(Covered under PRC-024) - Differential (87) (Not applicable to standards as it is protection for the unit) Alternatively, perhaps a table listing excluded elements could be added to the back of the standard, and referenced in the 4.2.1 Applicability section. Here is an example of what 4.2.1 might look like: ?4.2.1 Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements with the exclusion of the elements listed in table XXX. ? 3) Regarding R2 M3 - Our technical justification to exempt the above excluded elements is: a) duplication in applicability to other standards, and b) the type of fault. Mandating technical justification beyond these two points puts an unnecessary burden on industry resources.

Response: Thank you for your comments.

1)a) The drafting team believes that most changes associated with Requirement 3, Part 3.3 would lead to a technical justification as to why a new PSCS is not required, but if one is required, then the six month window is more appropriate than a twelve month window. That is because a Protection System change has been made and not just a modeled change in fault current. The drafting team believes the evidence required in the measure is appropriate and necessary to show that the PSCS has been completed. The drafting team believes that the varying timeframes for the different parts of Requirement R1 are appropriate based on the different required action timeframes in the different Parts. No change made to the standard.

b) The change in Fault current is based on the cumulative change in Fault current since the last PSCS because fault currents can gradually change based on system modifications that are unrelated to interconnections. Those Fault currents could be significantly different from the most recent PSCS even though an annual change may never reach the 10% threshold. The drafting team believes the evidence required in the measure is appropriate and necessary to show that the PSCS has been completed. The drafting team believes that the varying timeframes for the different parts of Requirement R1 are appropriate based on the different required action timeframes in the different Parts. No change made to the standard.

c and d) The drafting team believes that the format of the data request is best left to the requesting entity and that the

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evidence required in the measure is appropriate and necessary to show that the PSCS has been completed. No change made to the standard. **2) The drafting team believes that the list of protection functions included in the section "Other Aspects of Coordination of Protection Systems Addressed by Other Projects:" provides the exclusion that you are suggesting and a detailed listing of element functions is not required. No change made to the standard.** **3) Thank you for your comment.**	
Kansas City Power and Light	1) The definition of Protection System Coordination Study should be changed to ?A study that documents the intended sequence of operation for clearing faults of an existing or proposed Protection System.? The word ?demonstrates? implies that live testing should be conducted to prove the sequence of operation. 2) In the Rationale for R1, Part 1.1.2, the following portion should be deleted, ?e.g. when a line is protected by dual current differential systems with no backup elements set that are dependent upon fault current.? The deleted portion should be replaced with ?Refer to the Application Guidelines for Requirement R2 for examples of protection systems where technical justifications may be used.? 3) Requirement R2 specifies a 10% change in fault current as the trigger for a review of the Protection Coordination. We believe that the only time that a Protection Coordination Study should be required is if the fault current increases by more than 10%. Fault studies are typically conducted with all generation on, but we know that this is not the normal system configuration year round and the system could be operating below the 10% fault current threshold. Unit outages are anticipated and fault detecting elements are set to operate even during outage conditions. Elements that coordinate at higher fault current values will coordinate at reduced values. Our suggested change would not preclude a Registered Entity from initiating a Protection Coordination Study upon the reduction of fault current by 10%.
Response: Thank you for your comments. **1) The drafting team has changed the word "demonstrates" to "documents" in the requirement but did not make the other**	

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changes suggested as it believes there is no improvement in the meaning. **2) The drafting team incorporated your suggested change.** **3) The Application Guidelines indicate that the short circuit studies performed for this function typically assume maximum generation and all Facilities in service. The drafting team believes that if changes are made to the Transmission system that result in lower Fault currents for those conditions that reach the trigger threshold, then a new PSCS is required. No change made to the standard.**	
Dominion	1). Under Requirement 2 (Page 8 of Redline Version), studies are referred to as ?most recent? and ?present? which is confusing and could be considered synonymous. Recommend changing this terminology to replace ?most recent? with ?previous? study and ?present? with ?new? study in all places within the standard where they exist. 2). Requirement R3, 3.1 first bullet (Page 10 of Redline Version) is both broad far reaching (new installation, replacement with different types) and specific (modifications to protective relays or protection functions settings, communications CT/PT ratios). 3.1 Clearing targets changes or additions to existing or new Facilities that modify conditions that impact coordination of Protection Systems. Recommend changing bullets to clarify areas of this emphasis to:? Change in Protective Relay Types or Functions? Change in Communication System(s) that interface with Protection System(s)? Change in connected voltage (VT) or current (CT) source ratios? Change to transmission system Element(s) that alters impedance? Change to generator unit (s) that alters impedance? Change to generator step-up transformer (s) that alter in impedance 3). In Application Guidelines ? Example Process (Page 30 of Redline Version) the second bullet indicates that a single study can be used whereas in R1 1.1.3 it states that ?each? entity shall perform a PSCS. Recommend clarification in this example to reflect Note that is included in Rational for R1 that indicates in cases where a single group performs overall study for the interconnection for both entities. This reference may lead to confusion in the example. 4). Wording is confusing in PRC-027-1 Applicability Section (Page 3 of Redline Version). Suggest combining 4.2 and 4.2.1 into something like ?Protection Systems owned by the

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	Functional Entities in 4.1 are applicable if they are installed for the purpose of detecting Faults on Interconnected Elements of the BES and require coordination for isolating those faulted Elements?. 5). There are numerous locations in the standard that note that ?Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.? Given the complexities of system configurations, it is not always the case that this scenario (Max Gen and All Facilities In) will be the best case under which to verify proper coordination. Recommend removing this note and require entities to determine the best scenario under which to evaluate coordination. The presence of this note may create unintended bias. 6). Dominion agrees with SERC PCS comment: ?Please change Figures 3 and 4 in the Applications Guidelines section so that ?Interconnected Element? is adjacent or points to the line between Breaker C and the point of connection (tap point) on the line between Breakers A and B. It clarifies these examples by having the Figures align with your wording. (The Figures presently imply that the line between Breakers A and B is the ?Interconnected Element?.)

Response: Thank you for your comments.

1) **The drafting team used "present" to qualify the short circuit study and "most recent" to qualify the Protection System Coordination Study, which are two different studies. It is only when the difference between the values in the two types of studies exceeds 10% does a new Protection System Coordination Study need to be performed. No change was made to the standard.**
2) **The first bullet refers to any changes made to the Protection System(s) and the drafting team does not believe it is necessary to individually bullet each component, whereas the other bulleted items refer to different types of changes that could change the impedance in the system. No change was made to the standard.**
3) **The drafting team believes that the Note in the rationale box for Requirement R1 and the second bullet in the Example Process are consistent and are adequate and sufficient to eliminate confusion about what is required. No change was made to the standard.**
4) **Based on yours and others' comments, the drafting team revised the Applicability section to remove 4.2.1.**

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5) The drafting team recognizes that engineering judgment will be used by entities to perform a PSCS. However, it believes that the language of the standard is accurate and appropriate. Since at least two entities will be performing or reviewing the PSCS, the drafting team believes that the appropriate system configuration will be used in modeling the system for the PSCS. There is no way to measure whether entities have determined "the best scenario under which to evaluate coordination." No change made to the standard. **6) The drafting team revised Figures 3 and 4 to indicate that the tap line is the Interconnecting Element.**	
Bureau of Reclamation	1. Reclamation requests that the drafting team clarify what "acceptable evidence" it envisions for PSCSs. For an example, is a PSCS acceptable if the document contains (a) Date of study, (b) Deviation of short-circuit currents, (c) System change, (d) all recipients, etc. We appreciate if you can include an example form/document as acceptable evidence. Reclamation would appreciate if the drafting team added a sample PSCS template that would be considered acceptable evidence. 2. In order to avoid similar vagueness of coordination issues that were problematic under PRC-001, Reclamation would appreciate if the drafting team clarifies what a PSCS should contain (e.g. which relay element(s) is required to coordinate with, how to show it as the evidence, etc.)The PRC-025 documents may provide helpful examples. 3. Regarding R1 & M1, if a PSCS shows no impact on the existing coordination (no setting changes are required), would an entity still have to send neighboring utility(s) the entire PSCS supporting study or would a brief statement of the study results suffice? Reclamation requests that the drafting team clarify the acceptable evidence. 4. Reclamation suggests that R2 should be revised to read, ?For each interconnected element on its System, the TO shall, once every 60 calendar moths, technically justify if a fault current has changed more than 10% but does not affect to the Power System

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	coordination, or ?? rather than "techincally justify why Fault current does not affect the Protection System coordination." 5. Reclamation requests clarification of the items requiring coordination listed in R3.1. Reclamation believes that the current list implies that any changes in relay equipment or settings would require coordination.
Response: Thank you for your comments. 1. The drafting team does not believe it should prescribe the content of the PSCS. Guidance for information that may be included in the summary of the PSCS is provided in the Application Guidelines section for Requirement R1. No change made to the standard. 2. The drafting team does not believe it should prescribe the content of the PSCS. Guidance for information that may be included in the summary of the PSCS is provided in the Application Guidelines section for Requirement R1. No change made to the standard. 3. Requirement R1, Part 1.2 only requires that a summary of the PSCS be provided to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s), regardless of whether there was impact on the existing coordination. No change made to the standard. 4. The drafting revised Requirement R2 to eliminate the use of a technical justification. 5. Your interpretation of Requirement R3, Part 3.1 is correct.	
Bonneville Power Administration	1. The definition of Protection System Coordination Study is inadequate because it does not address what type of faults must be studied or where on the system the faults need to be applied. 2. R1.1.2 uses the term interconnecting bus. This is not a common term and requires a definition.
Response: Thank you for your comment. 1. The drafting team believes that the definition, as written, includes operation of Protection Systems in the intended sequence for all types and locations of Faults. No change made to the standard. 2. The figures in the Application Guidelines show the intent of the drafting team with regard to "interconnecting bus." No	

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change made to the standard.	
Exelon and its Affiliates	a. For voltage levels at 345Kv and above (EHV), our standard Protection System design utilizes two high-speed pilot schemes, and includes time-delayed backup protection. Due to pilot scheme redundancy, the operation of time-delayed backup elements is an extremely rare event. Our time-delayed backup protection is intended to serve only as a safety net for extreme events and we do not believe it is cost effective to study time coordination of these elements across our EHV systems. We believe that in cases where high speed protection schemes are redundant, that is designed such that loss of a single relay or auxiliary relay will not result in relying on time-delayed backup relaying to clear faults, the study of back-up element coordination is not necessary and the completion of a PSCS should not be required. b. Additionally, we believe Requirement 1 should state how many protection system failures must be considered for a PSCS. We believe that only one failure is appropriate for the reasons discussed above. c. PRC-001: The proposed Violation Severity Levels for PRC-001-3 R1 are not commensurate with the draft Measure of the Requirement. The current VSL is ?High? for failure to be ?familiar with the limitations of the protection system schemes applied in its area? and ?Severe? for failure to be ?familiar with the purpose of protection system schemes applied in its area.? The draft Measure states that the applicable entity ?shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel.?The VSLs should be revised to align with the Measure and the ?intent? of the Standard and not effectively split out the purpose of Requirement R1 thus requiring specific documentation for a ?purpose? and a ?limitation?. Exelon suggests the VSLs be revised to the following: Severe: The responsible entity failed to provide evidence that any training evidence exists for basic relaying and any Special Protection Systems within its area. High: The responsible entity failed to provide evidence that all applicable personnel

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	were trained in basic relaying and any Special Protection Systems within its area d. PRC-001: In the Background Section of PRC-027-1 there is a discussion related to PRC-001-1 that was revised as part of Project 2007-03. Specifically, it is stated that in Project 2007-03 SDT retired PRC-001-1 Requirement R2 as because this Requirement addresses data and data requirements that are included in the proposed Reliability Standard TOP-003-2; however, the justification provided in the mapping document associated with Project 2007-03 does not seem to meet the original intent of PRC-001 R2, and does not seem to be a "relocation" of the original requirement (refer to Project 2007-03 Mapping Document Draft 7). PRC-001-1 R2 current revision is as follows:R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. The Background Section of PRC-027-1 further states that the SPC SDT recommends that Requirement R1 remain in PRC-001-2, until its reliability objective is addressed by either a revision to an existing standard or development of a new Standard. The current revision to PRC-001-2 that removed Requirement R2 was not fully addressed by Project 2007-3 nor voted on by the Ballot Body and therefore Exelon requests that PRC-001-1 R2 be added back in to PRC-001-3 and Project 2007-06, similar to Requirement R1, until its reliability objective by similarly addressed by either a revision or development of a new Standard.

Response: Thank you for your comments.

a. **The drafting team believes that the initial PSCS required in Requirement R1, Part 1.1 must be completed to ensure that present coordination exists. If, during that PSCS, the entity can confirm that the coordination is not affected by changes in Fault current, then the entity can apply that technical justification to Requirement R1, Parts 1.1.2 or 1.1.4. The application of redundant Protection Systems does not preclude the necessity of ensuring that your Protection Systems are coordinated.**

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b. The drafting team does not believe that it should prescribe the details of performing PSCS and leaves that to the engineering judgment of the entities performing the PSCS. No change made to the standard. c. After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PRC-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities. d. After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PRC-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.	
Essential Power, LLC	a. R3.3 should be limited to Protection Systems associated with Interconnected Elements. b. There is no change needed to the present system:-The TOP is provided with detailed information of GO equipment via PRC-001 and MOD-010, and the TO (being informed of these inputs by the TOP) is then at liberty to modify their Protection Systems if needed. -We periodically request data for available fault current at the interconnect point from the TO, for use in our aux system short circuit studiesChanges in the T&D system otherwise don?t matter to GOs. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is

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	in the TO?s system. The most that could reasonably be asked of independent GOs is to have a valid Interconnection Service Agreement (ISA), since a coordination study is performed by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so detailed evidence could not be asked of the GO.The SDT states on p.21 of PRC-027 that ?The drafting team has no evidence there is widespread mis-coordination between Owners of Facilities,? and, ?records collected for reliability standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.? This appears to indicate that the present system is working and therefore there is no need to go back to existing unit?s coordination studies to make sure they crossed all of the T?s and dotted all of the I?s according to a standard that retroactively applies requirements that were not in existence at the time of the original coordination studies. c. The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027 back into PRC-001. Please retain one measure per requirement so that the Measurement numbers match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts.

Response: Thank you for your comments.

a. **The drafting team made the suggested change to Requirement R3, Part R3.3.**
b. **PRC-027 is replacing the Protection System coordination aspects of PRC-001.**
c. **After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PRC-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2**

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and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.	
Associated Electric Cooperative, Inc.	AECI seeks additional clarify of the SDT's intent as to how base PSCS requirements are to be applied within a JRO, and if R1-R2 serves legitimate reliability function, where R1.1.3, & R3-R4 do not apply to intra-JRO interconnected elements because JROs already internally do these; a JRO would still perform R1.1.3 & R3-R4 for interconnected elements with other registered entities; also clarify that R1 would only require one ?master? PSCS for the JRO as opposed to multiple studies for each functional entity within the same JRO.
Response: Thank you for your comment. **The drafting team believes that the Joint Registration Organization (JRO) is responsibile for coordinating all of the Protection Systems associated with Interconnecting Elements between the JRO and its neighboring entities (external to the JRO), and between the applicable internal JRO registrations (e.g. TO, GO).**	
ATCO Electric	Can the drafting team draw all timelines in 4 requirements together in a chart to see how these timelines fit together for an entity?
Response: Thank you for your comment. The drafting team does not believe a separate chart illustrating timelines is necessary since the Process Flow Chart in the Guidelines and Technical Basis section of the standard is a representation of the process, including the relationships between requirements and timeframes.	
DTE Electric	Comments: Different entities that are highly integrated electrically should be using the same short circuit data. If fault data files could be exchanged regularly (bi-annually?) using compatible file formats, short circuit databases wouldn't drift apart (as would occur after five years) and coordination studies could be performed with more confidence. Many settings could require re-visiting when the once every five year fault current update is received. It should be noted that while the emphasis is on BES Interconnected Elements, many other non-BES Interconnected Elements, such as radial distribution transformers, could be affected resulting in a negative impact on the BES.

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Response: Thank you for your comment. The drafting team agrees with your comments but there is not a current standard requiring that entities do not use the same short circuit studies, nor does this proposed standard require that. The fault current evaluation is a relatively small component of this standard and the drafting team does not expect that there will be significant disagreement between entities when one entity finds that the fault current has changed by 10%.	
Texas Reliability Entity	How many buses away from the Interconnect Element does the PSCS need to cover? Figure 5 of the Application Guidelines indicates that only the next adjacent bus is to be included in the PSCS, which implies that the PSCS only covers up to Zone 2. We understand that PRC-027 does not tell any owner how to perform a PSCS or dictate the specific information that is required for a PSCS. It appears from our understanding that the coordination of protective relays beyond the primary zones that affect the interconnected element are the responsibility of the equipment owner, and that it is up to the owner to determine whether these settings are to be shared with other entities for the interconnected element. Please clarify if this understanding is correct.
Response: Thank you for your comment. Your understanding of equipment owner responsibilities for performing a PSCS in accordance with the draft standard is correct.	
Dynegy	If a Generator Owner does not own a Protection System associated with an Interconnected Element, does the Standard apply? For instance, if the generator breaker opens only for faults on the Generator Owner side of the breaker (i.e., GSU or generator faults). Is it expected most GOs will own Protection Systems associated with an Interconnected Element?
Response: Thank you for your comment. Per the Applicability section, the standard only applies to the Protection Systems owned by a TO, GO, or DP that are “installed for the purpose of detecting Faults on Interconnecting Elements of the BES and that require coordination for isolating those faulted Elements”. The drafting team does expect that most GOs will own applicable Protection Systems.	
Illinois Municipal Electric Agency	1. Illinois Municipal Electric Agency (IMEA)supports comments under Question 8 submitted by the SERC EC Protection and Control Subcommittee.

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	2. Also, IMEA requests that Figure 3 be modified or a separate figure be included to clarify guidelines for DP systems that include only non-BES generation. 3. IMEA also requests that Applicability Section 4.2.1 be revised to prevent inconsistency with the FERC-approved interpretation of transmission Protection System as specified in PRC-005-1b. Very specific attention/consideration needs to be given to avoiding unnecessary expansion of applicability to facilities owned by small Distribution Providers; i.e., unnecesarry expansion of scope to protective devices owned by a DP that have no potential adverse impact on the BES. Both FERC and NERC have stated the need to minimize impacts on small entity resources.
Response: Thank you for your comment. 1. **Please see the response to SERC EC Protection and Control Subcommittee (SERC RRO).** 2. **If a DPs system includes only non-BES generation, and the associated Protection Systems are not installed for the purpose of detecting Faults on Interconnecting Elements of the BES, this standard would not apply to coordination of those Protection Systems. Whether or not the generator in Figure 3 is BES or not does not determine the Distribution Provider's applicability to this standard; the qualifier is whether or not the associated Protection Systems are installed for the purpose of detecting Faults on Interconnecting Elements of the BES.** 3. **The term "transmission Protection System", to which the interpretation you reference applies, is not used in the Applicability section (or within any other portion) of PRC-027-1. Therefore, the draft standard contains no inconsistencies with the FERC-approved interpretation, which was issued to clarify the use of the term in reliability standards PRC-005-1b and PRC-004-2a. Per the Applicability section of PRC-027, the standard only applies to the Protection Systems owned by a TO, GO, or DP that are "installed for the purpose of detecting Faults on Interconnecting Elements of the BES and that require coordination for isolating those faulted Elements".**	
Lincoln Electric System	In consideration that the rationale for Requirement R1 Part 1.1.1 acknowledges that the drafting team has ?no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements?, LES recommends further development of the standard be halted until sufficient technical justification can be provided for the standard?s development. As currently drafted, the drafting team would

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	place excessive documentation requirements on registered entities for activities already being performed as industry best practices. In lieu of turning those best practices into compliance requirements, LES suggests the drafting team leverage existing Reliability Standard PRC-001 as a basis for system protection coordination.
Response: Thank you for your comment. PRC-027-1 is intended to transfer the requirements of PRC-001 that are associated with actual coordination of Protection Systems necessary for proper performance during faults. In doing so, the drafting team is leveraging PRC-001 as a basis for system protection coordination as well as following the recommendations of the NERC System Protection and Control Task Force (now a Subcommittee – SPCS) in its 2007 *Assessment of Standard PRC-001-0 – System Protection Coordination*, and addressing observations from the Commission in FERC Order 693. The Project 2007-06 – System Protection Coordination drafting team has taken this course after consultation with both NERC and FERC staff. The drafting team believes that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.	
FirstEnergy Corp	In regard to PRC-027-1: 1. We believe that R3, Part 3.1 is covered in R1, Part 1.2 2. …and propose that R4, part 4.2 be reworded to: 4.2. Prior to implementing any proposed change (s) or modifications associated with Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues In regard to PRC-001-3: 3. The title for PRC-001 "System Protection Coordination" and the purpose statement of this standard is no longer pertinent for the only requirement that remains in the standard - entity familiarity with the purpose and limitations of protection system schemes. This remaining requirement is essentially a training obligation and better suited in a PER standard if deemed necessary for reliability. The drafting team also appears to support this view as discussed in the background statements of the PRC-027-1 standard, however, believes this additional work is outside the scope of its project. However, the PRC-001-3

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	standard should not be left with a title and purpose statement that will cause industry confusion with PRC-027-1. We suggest that this team adjust PRC-001-3 to include the title ?System Protection Awareness? and a purpose statement of ?To ensure entity understanding of system protection schemes applied to their assets.?FE believes the continuing need for this requirement (PRC-001-3 R1) needs to be carefully considered. NERC standards PRC-023 and PRC-25 address relay loadability limitations. The original blackout report recommendation that drove this requirement appears to now be more thoroughly addressed by those standards. We encourage the NERC Standards Committee to extend the scope of this drafting team?s work through a supplemental SAR to address whether or not PRC-001 can be retired.

Response: Thank you for your comment.

1. **Requirement R3, Part 3.1 stipulates that TOs, GOs, and DPs with applicable Protection Systems must provide information regarding proposed system changes or additions that may affect the other owner(s) associated with an Interconnecting Element. The objective of this requirement is to enable the process of conducting Protection System Coordination Studies (PSCS). Requirement R1, Part 1.2, on the other hand, requires TOs, GOs, and DPs with applicable Protection Systems to provide a summary of results of the PSCS once the study has been completed (within 90 calendar days). These two requirements are not synonymous.**
2. **For clarity, the drafting team has removed Requirement R4, Part 4.2 and created new Requirement R5, which states: "Prior to implementing any proposed change(s) or addition(s) associated with Requirement R3, Part 3.1, each Transmission Owner, Generator Owner, and Distribution Provider shall confirm there are no outstanding coordination issues associated with the affected Interconnecting Element."**
3. **After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PER-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2**

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and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.	
Duke Energy	1. In the interest of clarity, Duke Energy feels an example of acceptable evidence for measure 3 of PRC-027-1 R2 would be beneficial. 2. In PRC-027-1, Duke Energy identified a potential gap in Figure 4 of the Application Guidelines. Duke Energy believes that without coordination between the DP and TO, it could lead Transmission Planners and System Protection Engineers to disregard the coordination with protection for the tap line between BES and non-BES equipment. Given the proposed definition of the BES, this scenario could potentially pose a risk to the BES without the proper coordination identified in PRC-027-1.
Response: Thank you for your comment. **1. The drafting team removed the option of performing a technical justification from Requirement R2 and consequently removed the associated Measure M3.** **2. Because there are no Protection Systems at Breaker C that protect for Faults on BES Elements, the subject Protection Systems are not applicable under this standard. The drafting team understands the commenter's point; however, this standard only applies to Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements.**	
Nebraska Public Power District	My general impression is this standard could be quite a burden to track data for an audit due to the numerous time lines specified that are between entities. My opinion is this will likely result in a difficult to audit standard. This causes concern if we remain in a zero tolerance compliance environment. Consider changing some of the time lines such as 30 and 90 days to 6 months. My general feeling is we should consider other ways to simplify this standard however suggestions I have made have not made it into the draft standard. I recommend more consideration be given to simplification.
Response: Thank you for your comment. The drafting team believes the different time frames are necessary and appropriate for each of the requirements. A process flowchart is included in the Application Guidelines to show how the different timelines are tied together. The individual Rationale boxes for each requirement provide the drafting team's reasoning for the different time	

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frames.	
PJM Interconnection	PJM supports both standards as drafted. Specific to PRC-001-3 R1, PJM urges the SDT to replace the term ?familiar? with language less subjective. There may be a number of interpretations for this term that will result in compliance issues for applicable entities. Suggested revised wording should include language that has a direct tie to the Measure. PJM recommends the following revised requirement for the applicable entities, ?knowledge of the purpose of and limitations of protection system schemes shall be based on the training programs provided.?
Response: Thank you for your comment. **After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PER-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.**	
SERC RRO	Please change Figures 3 and 4 so that ?Interconnected Element? is adjacent or points to the line between Breaker C and the point of connection (tap point) on the line between Breakers A and B. It clarifies these examples by having the Figures align with your wording. (The Figures presently imply that the line between Breakers A and B is the ?Interconnected Element?.)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.
Response: Thank you for your comment. The drafting team revised Figures 3 and 4 to indicate the tap line is the Interconnecting	

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Element.	
American Electric Power	1. PRC-001-3: R1 ? The term ?protection system? should be capitalized to match previous versions of this standard. 2. PRC-027-1: Mapping Document ? The verbiage in R1.1 of the mapping document does not match the wording in the proposed standard: ?Protection System Study? is used instead of ?PSCS?. 3. PRC-027-1: Figure 2 ? The phrase ?generator Protection Systems? is often used by Generation Owner relay engineers to mean the Protection Systems installed for the purpose of detecting faults on and protecting the physical generator, which is clearly outside of the scope of this standard. Therefore, AEP recommends changing the verbiage associated with this figure to remove the phrase ?generator Protection Systems? and replace it with a reference to Generator Owner R?s Protection Systems installed for the purpose of detecting faults on the Interconnected Elements. Suggested wording is shown below: Transmission Owner S is to review the Protection System settings associated with Breaker A *and the Interconnected Element* (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, Owner S is to develop proposed Protection System settings associated with Breaker C. Generation Owner R is to review the Protection System settings associated with Breaker C *and the Interconnected Element* (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A. 4. PRC-027-1: R3 & Figure 5 ? As written, R3 will place undue burden on each TO, GO and DP to maintain a list of all other entities connected to each interconnecting bus to which they connect. Furthermore, since the elements are typically owned by the TO, burden will be placed on the TO to respond to requests from other TO?s, GO?s and DP?s as they build their list. R3 and its? associated Figure 5 should be revised such that the responsibility lies with the

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	owner of the Interconnected Element to ensure that relevant information is passed along to each entity who connects to the element when any one entity makes a change.

Response: Thank you for your comment.

1. **After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PER-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.**
2. **The drafting team has made the suggested revision to the mapping document.**
3. **The drafting team sees no benefit in making the suggested change and believes your issue is addressed by the Applicability section of the standard which specifies the Facilities included by this standard.**
4. **The drafting team believes that entities making changes or additions to Protection Systems associated with an Interconnecting Element must communicate the proposed changes to the other interconnected owner. As noted in Figure 5, it may be necessary for that other interconnected owner to forward the provided information to the other owners.**

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Northeast Power Coordinating Council	1. PRC-027-1 in its entirety needs a quality review. Requirement R2 is not written correctly--it does not refer to the entities first. Also, each Requirement has multiple numbered Measures. 2. The Requirement also states that the functional registration (e.g. GOP) has to demonstrate compliance, not the individual operators. If it is the intent of the Standard that each individual operator of an entity be familiar this should be added. By stating the functional registration as opposed to the individuals, it could be interpreted that as long as any Registered Entity SME is familiar with the purpose and limitations of the protection systems that the entity will be able to demonstrate compliance. Suggested rewording of the Requirement:

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	Each Transmission Operator, Balancing Authority, and Generator Operator responsible for the operation of BES elements shall have its operators be familiar with the purpose and limitations of protection system schemes, either through training or operational experience, applied in its area. There has been a broad variation in how the language of this requirement is applied during audits.
Response: Thank you for your comment. 1. **PRC-027-1 has been through numerous quality reviews and meets NERC's guidelines for standard's development.** 2. **After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PER-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.**	
Madison Gas and Electric Company	1. PRC-027-1:The proposed standard contains 30-day and 90-day timing requirements in addition to the 60-month requirement. Please consider revising the 30 calendar day?s provision in requirements R2.2.1, R3.2 and R3.3 to 90 calendar days to avoid possible confusion between different timing requirements in the standard. We do not see a basis on why there needs to be different dates. If all dates were 90 days, it would provide consistancy for entities to follow. 2. In consideration that the rationale for Requirement R1 Part 1.1.1 acknowledges that the drafting team has ?no evidence there is widespread mis-coordination of Protection Systems associated with Interconnected Elements?, LES recommends further development of the standard be halted until sufficient technical justification can be provided for the standard?s development. 3. As currently drafted, the drafting team would place excessive documentation

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	requirements on registered entities for activities already being performed as industry best practices. In lieu of turning those best practices into compliance requirements, NSRF suggests the drafting team leverage existing Reliability Standard PRC-001 as a basis for system protection coordination. 4. PRC-001-3: Please consider revising the Purpose of PRC-001-3 to reflect the one remaining requirement. With the updated measure there is an inconsistency between the Purpose, the Requirement, and the Measure. We suggest revising the Purpose to PRC-001, the following: To ensure familiarity with the purpose and limitations of protection systems operated by the entity. Suggest revising Requirement R1 to: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall train its applicable personnel to be familiar with the purpose and limitations of protection systems operated by the entity. The above rewrite now provides a clear and understandable (plus it adds to system reliability) Standard for the applicable entities to follow. The Standard sets a minimum level of training concerning protection systems that entities operate. An entity can always provide training on non-operated protection systems, whereby the entity has determined (based on risk to their system) the scope of training outside the proposed rewrite.

Response: Thank you for your comment.

1. **The drafting team believes the different time frames are necessary and appropriate for each of the requirements. A process flowchart is included in the Application Guidelines to show how the different timelines are tied together. The individual Rationale boxes for each requirement provide the drafting team's reasoning for the different time frames.**
2. **The drafting team believes that the draft standard provides a reliability benefit of ensuring that all existing, modified, or new Protection Systems on Interconnecting Elements are coordinated for proper performance during Faults. The drafting team believes that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.**

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3. PRC-027-1 is intended to transfer the requirements of PRC-001 that are associated with actual coordination of Protection Systems necessary for proper performance during faults. In doing so, the drafting team is leveraging PRC-001 as a basis for system protection coordination as well as following the recommendations of the NERC System Protection and Control Task Force (now a Subcommittee – SPCS) in its 2007 Assessment of Standard PRC-001-0 – System Protection Coordination, and addressing observations from the Commission in FERC Order 693. The Project 2007-06 – System Protection Coordination drafting team has taken this course after consultation with both NERC and FERC staff. **4. After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PER-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.**	
Southwest Power Pool	1. PRC-027-1 As drafted the standard contains 30-day and 90-day timing requirements in addition to the 60-month requirement. Would the drafting team consider making the 30-day and 90-day requirements the same, for example 90 days? This would make staying abreast of timing issues much simpler. 2. Figure 4, Application Guidelines The Note at the bottom of Figure 4 is misleading in that it states that no PSCS is required under this scenario. However, Transmission Owner R is required to have a PSCS for the Interconnected Element between Breakers A and B. The Distribution Provider S is not required to have a PSCS for Breaker C. 3. PRC-001-3: Purpose The existing purpose does not fit the single requirement that is left in the standard. We would suggest changing the purpose to the following:

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	To ensure familiarity with system protection schemes utilized within an operating entity?s area. Requirement R1Similarly, the requirement does not match the proposed measure. We suggest modifying the requirement to: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall train its applicable personnel to be familiar with the purpose and limitations of protection system schemes applied in its area.

Response: Thank you for your comment.

1. **The drafting team believes the different time frames are necessary and appropriate for each of the requirements. A process flowchart is included in the Application Guidelines to show how the different timelines are tied together. The individual Rationale boxes for each requirement provide the drafting team's reasoning for the different time frames.**
2. **The drafting team revised Figure 4 to provide additional clarity that the Distribution Provider S depicted does not own a Protection System installed for the purpose of detecting Faults on the Interconnecting Element and is therefore excluded from this standard.**
3. **After much deliberation, the drafting team and NERC staff are recommending the retirement of PRC-001-2. The reliability objective of PRC-001-2, Requirement R1 is incorporated in the proposed Reliability Standard PER-005-2 Operations Personnel Training (Project 2010-01 Training). The aspects of coordination addressed in Requirements R2 and R3 of PRC-001-2 are incorporated in proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for your review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.**

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Public Service Enterprise Group	PSEG has the following additional comments: a. To avoid make-work reporting that is detrimental to BES reliability, PSEG recommends that the Applicability section remove Protection Systems, Interconnected Elements, and Protection System components that do not require coordination. Therefore, we propose that the 4.2.1 be modified with this additional language after ?faulted Element?: ?,

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	except for the following Protection Systems, Interconnected Elements, and Protection System components that do not require such coordination:? Protection Systems for the Interconnected Element that are owned by the same functional entity of a single Registered Entity.? An Interconnected Element that is protected by overlapping differential relays only (e.g., a Generator Owner?s GSU that is connected to a Transmission Owner?s bus)? Protection System components for which coordination is unaffected solely due to an increase in Fault current, including:? Transformer differential relays? Line current differential schemes? Generator differential or overall differential, bus differential schemes? Step distance protection schemes? Fault detector settings (these settings are guided directly by PRC-023-X)? Breaker failure settings? Directional Comparison Blocking overcurrent schemes b. ?Application Guidelines? Comments More clarity on what a pre-standard PSCS needs to contain to meet R1.1. Is an e-mail trail from other owners stating that the settings are acceptable? Do calculations need to be shown? c. Language on p. 21: ?The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnected Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.? If there is no problem, why is this standard being proposed? d. Language on p. 22 that lists examples of Protections Systems where technical justification may be used to exclude the need for a PSCS. Although PSEG has suggested limiting the Applicability in its comments in 8.a, it may be simpler if the standard just listed the Protection Systems that require a PSCS ? that would only be overcurrent elements based upon Fault current. If that scheme is not employed, no PSCS is needed.
Response: Thank you for your comment.	

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a. The drafting team declines to list the exclusions you suggest, but has revised the Applicability section for clarity as follows: 4.2 Facilities: Protection Systems: a) installed for the purpose of detecting Faults on Interconnecting Elements, and; b) that require coordination for isolating those faulted Elements. b. The parenthetical phrase in Requirement R1, Part 1.2 provides the clarity you request. "…a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection System(s) reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed), …." c. The drafting team believes that the draft standard provides a reliability benefit of ensuring that all existing, modified, or new Protection Systems on Interconnecting Elements are coordinated for proper performance during Faults. The drafting team believes that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES. d. The drafting team declines to list the inclusions you suggest, but has revised the Applicability section for clarity as follows: 4.2 Facilities: Protection Systems: a) installed for the purpose of detecting Faults on Interconnecting Elements, and; b) that require coordination for isolating those faulted Elements.	
ReliabilityFirst	ReliabilityFirst offers the following comments for consideration: 1) Requirement R1, Part 1.2 - ReliabilityFirst recommends converting the parenthetical last sentence ?(including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed)? into four separate and distinct sub-parts. Separating these out will clearly spell out to the applicable entity and compliance auditors the specific items which are required to be provided. Listed below is an example for consideration: 1.2.1 Protection Systems Reviewed 1.2.2 Associated fault currents 1.2.3 Identified issues 1.2.4 Proposed revisions or actions 2) Requirement R2, Part 2.2 - Within both the clean and redline version of the posted

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	draft standard, the equation referenced at the end of Requirement R2, Part 2.2 is inadvertently missing and therefore needs to be added back into the requirement.

Response: Thank you for your comment.

1. **The drafting team believes the items listed in parenthetical form provide the example in a clear manner.**
2. **The drafting team apologizes for that oversight. A new version with the equation was made available on the NERC web site on June 21, 2013.**

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Clark Public Utilities	Requirement 3 (and any sub-requirements) should not be applicable to any Interconnection Element owners that are part of the ?same Registered Entity that represents multiple functional entity responsibilities.? Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the same functionally registered entity that developed the details for proposed changes to provide a documentation of those details to all other functionally registered entities. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of ?Separate Registered Entities and ?Same Registered Entities? it is suggested that the wording be modified to incorporate theses terms as follows: R3. Each Separate Registered Entity and each Same Registered Entity shall provide to each other Separate Registered Entity connected to the same Interconnected Element: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning] 3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnected Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the

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	Interconnected Element(s).? New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios? Changes to a transmission system Element that alter any sequence or mutual coupling impedance? Changes to generator unit(s) that result in a change in impedance? Changes to the generator step-up transformer(s) that result in a change in impedance 3.2. Requested information related to the coordination of Protection Systems associated with an Interconnected Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule. 3.3. Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.
Response: Thank you for your comment. The drafting team does not agree because they are cases where the Transmission Owner and Generator Owner are part of the same Registered Entity but separate technical groups are involved in performing the required Protection System Coordination Studies. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."	
City of Tacoma	Tacoma Power appreciates the efforts of the SDT. This is a difficult process and topic on which to standardize. 1. It would help, especially for the Flowchart, if R1.1.3 could be separated into a revised R1.1.3 ?according to an agreed upon time frame to meet the schedule

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	when proposing or being notified of a change, as described in Requirement R3, Part 3.1; or technically justify why such a study is not required? and a new R1.1.4 ?within six calendar months of being notified of a change as described in Requirement R3, Part 3.3; or technically justify why such a study is not required.? 2. In R3.1, the language ?or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)? appears to be very open-ended with respect to the second, third, and fourth bullets under R3.1. In theory, any impedance change within an entity?s system could qualify, which brings into question potential overlap between R2 to address incremental changes and R3.1. R3.1 should establish a brighter line for what triggers an entity to begin coordination activities for proposed impedance changes not at an existing or new Facility associated with the Interconnected Element. In other words, at what point is an impedance change considered an incremental change and, therefore, applicable to R2, as opposed to R3.1? 3. In the Flowchart, the arrows are confusing above the decision diamond ?(R1.1.3) Is a new PSCS required?? 4. Referring to M2, M5, M7, and M8, is any confirmation of receipt required in order to demonstrate that a responsible entity ?provided? the information? It is recommended that evidence of receipt not be required to demonstrate that an entity ?provided? information applicable to these measurements. 5. Referring to the Application Guidelines, Figure 5 and associated discussion, the introductory paragraph statement ?in Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be check for coordination with Generator Owner T? appears to contradict the discussion on page 39 of 40 of the redlined copy of PRC-27-1.

Response: Thank you for your comment.

1. **The drafting team made the suggested change.**
2. **Requirement R2 addresses the periodic performance of Fault current studies, using an entity's short circuit model, in order**

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to maintain awareness of Fault current changes (not incremental impedance changes) that could affect proper performance of Protection Systems. Requirement R3 addresses communication of physical changes or additions, such as those that alter impedance values, so that entities can keep their Protection System databases and short-circuit models up-to-date for the performance of accurate Protection System Coordination Studies. 3. The drafting team revised the flowchart to provide clarity. 4. The requirements mandate that entities provide information. The measures complement the requirements in suggesting evidence that is appropriate or acceptable to satisfy compliance with the requirement. The measures state that acceptable evidence is documentation demonstrating that the information was provided within the specified timeframe. No confirmation of receipt is required as evidence. 5. Although Transmission Owner S has no Protection Systems located at Station 1, Owner S does have other Protection Systems that require coordination with the Generator Owner; therefore, the language is not contradictory.	
Idaho Power Co.	Thank you for the opportunity to comment. While we are in favor of this version, we seek clarification on one item. Requirement R2 states that the fault values used in determining the 10% change will be measured at the ?interconnecting bus?. While reviewing the examples in the application guideline section, two ?interconnecting bus? are labeled in Figure 1, 3, and 4. If the coordination concern is related to the interconnecting element, it would seem reasonable that the ?interconnecting bus? for Owner S to place faults on to determine the 10% change is that at Station 1/Transmission owner R, looking at figure 1. This would capture the change in fault current seen by the Owner S Protection System on breaker E. Placing faults on the interconnecting bus behind breaker E if I am owner S does not seem appropriate when considering coordination on the interconnecting element.
Response: Thank you for your comment. In reference to Figure 1, the intent is for each Transmission Owner to check for changes in Fault current at its own interconnecting bus; if either owner identifies a 10% change, it would notify the other owner pursuant to Requirement R2, Part 2.2.1.	
CenterPoint Energy	The draft for PRC-027-1 states: ?records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.? CenterPoint Energy considers the proposed requirements to be too

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	prescriptive for Protection System coordination when it has not been identified as a reliability issue and expects such requirements would provide little, if any, reliability benefits. We believe the majority of existing Interconnected Facilities have time-proven and fault-proven Protection System set points and that newer facilities, including replacement relay panels, are commissioned utilizing appropriate coordination studies that include necessary interaction between interconnected entities. CenterPoint Energy recommends reevaluating the need for this standard with consideration that this subject area could instead be addressed by continuing to focus on misoperation analysis and through best practices initiatives.
Response: Thank you for your comment. The drafting team believes that the draft standard provides a reliability benefit of ensuring that all existing, modified, or new Protection Systems on Interconnecting Elements are coordinated for proper performance during Faults. Further, it should be noted that existing standard PRC-001-1 currently requires coordination of protection systems for new facilities and those associated with changes to existing facilities. PRC-027-1 clarifies the intent of the requirements of PRC-001 related to coordination; replacing those requirements and correcting the applicability to the equipment owners. The drafting team believes that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.	
California ISO	The ISO feels that a requirement should be added for the TO, GO or DP to notify their TOP and PC when a new or revised Remedial Action Scheme or Special Protection System is implemented.
Response: Thank you for your comment. There are other NERC Reliability Standards that address your comment regarding notification of new or revised RASs or SPSs.	
SMUD	The timing provided in R3.1 is contains no specification that correlate to the timing requirements of the other R3 subrequirements .
Response: Thank you for your comment. The drafting team believes that specifying a single time frame for Requirement R3, Part 3.1. is not appropriate for the wide variety of conditions, associated with the bulleted list, that will need to be evaluated.	

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Tri-State G &T	Tri-State is concerned about the timeframes allowed in Requirement R1, associated with Requirement 3, Part 3.1, especially when the proposed change does not affect the conditions used in the coordination of Protection Systems. The way we read Requirement R3, Part 3.1, a planned relay replacement will have to go through the PSCS process or a technical justification would be required even if it does not affect coordination of other Protection Systems. We would propose that Part 3.1 be changed as follows: 3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnected Element if the proposed change requires a change in the coordination of Protection Systems associated with the Interconnected Element(s); or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).
Response: Thank you for your comment. The drafting team believes changes associated with the bulleted list in Requirement R3, Part 3.1. must be communicated to the other owners associated with an Interconnecting Element so that each owner can verify the changes do not affect their Protection systems and so they can keep their Protection System databases and models up-to-date.	
ITC	1. We vote to reject Draft 3 of PRC-027-1 primarily due to enormous increase in administrative burden with no appreciable gain in system reliability. We agree with SDT there is reliability benefit to performing these tasks. However, as the SDT members stated at presentations to RFC Protection Subcommittee and to NATF Workshop, utilities are already doing this work. The SDT?s own rationale states ?no evidence there is widespread miscoordination of Protection Systems?. Therefore, the only outcome of this standard is that utilities will greatly increase administrative burden to become auditable. 2. Figure 4 exclusion of PSCS on the Interconnected Element is not found in standard. Figure 4 states the line or tap is the Interconnected Element, therefore TO owns ?facilities? and must meet R1-R4. Either definition of Interconnected

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	Element must be revised to exclude Figure 4 example, or Figure 4 must be corrected to show TO is still responsible for R1-R4. 3. Example Figures 1-5 create responsibilities on owners to ?propose? and ?review for coordination? which are not found in the standard. Either these responsibilities should be removed from Figures or the responsibilities should be added to the standard. 4. The last sentence in Figure 5 specifies the TO will provide GO settings to the other TO. This contradicts R3 which states, ?Each TO, GO, and DP shall provide to each TO, GO, and DP?? Again, the Figures are creating responsibilities not found in the standard. 5. The purpose of Applicability section 4.2 Facilities is unclear. Each requirement deals with requirements around the Interconnected Elements. If the purpose of section 4.2 is to try and exclude DP relays which do not purposefuly trip for BES faults, this should be more clearly stated. This exclusion should be moved to Interconnected Element definition and section 4.2 rewritten to target Interconnected Elements. Or section 4.2 should be the corrected Interconnected Element definition, and there will be no need for a new definition in this standard. 6. Example Figure 2 creates different responsibilities for GO than Figure 3 does for DP. Why the difference? Essentially they are the same: both have protection systems which trip for faults on Interconnected Element. Again, the Figures are creating responsibilities not found in the standard.

Response: Thank you for your comment.

1. **The drafting team believes that the draft standard provides a reliability benefit of ensuring that all existing, modified, or new Protection Systems on Interconnecting Elements are coordinated for proper performance during Faults. The drafting team believes that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.**
2. **The drafting team modified Figure 4 to address your concern.**

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	3. The Figures included in the standard are designed to provide examples of how to apply the requirements of PRC-027. Requirements associated with the proposal and review of Protection System design and settings can be found in Requirements R3 and R4, respectively. However, the drafting team modified the language in the figures to address your concern. 4. The drafting team believes the responsibilities described in the example you are noting, are consistent with the requirements of the standard. The TO in the example (Transmission Owner R) will have settings provided from Generator Owner R, through its obligation under Requirement R3, and will, in turn, be required, itself, by Requirement R3, to provide these settings to Transmission Owner T so that it can perform a PSCS. 5. The drafting team believes the Applicability section of the standard is clear in its intent to exclude coordination of Protection Systems, regardless of Registered Entity ownership, that are not "…installed for the purpose of detecting Faults on Interconnected Elements of the BES". 6. Figure 2 represents a BES generator connected to a BES transmission station where the Generator Owner has Protection Systems associated with breaker A that operate for faults on the Interconnecting Element. The drafting team believes the responsibilities outlined in Figure 2 for the equipment owners are consistent with the requirements of PRC-027-1. Figure 3 represents a generator (or network system) that is not connected to, or part of, the BES. However, in this figure, the Distribution Provider S does have a Protection System at the facility that is "…installed for the purpose of detecting Faults on Interconnecting Elements of the BES" (which trips breaker C) and, therefore, coordination of that Protection System is required by PRC-027. Again, the drafting team believes the responsibilities outlined in Figure 3 for the equipment owners are consistent with the requirements of PRC-027-1.

END OF REPORT