Meeting Notes

Project 2007-06 System Protection Coordination Standard Drafting Team

January 22-24, 2013

NERC Headquarters
Atlanta, GA

Administrative

1. **Introductions**

   The meeting was brought to order by Chair, Phil Winston, at 8:30 a.m. ET on Tuesday, January 22, 2013. Building and safety information/logistics were provided by Al McMeekin. 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	
Forrest Brock	Western Farmers Electric Cooperative	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	
Al McMeekin	NERC Staff	Member	X	
Tom Bradish	FERC	Observer	X	
David Youngblood	Luminant	Observer	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 nine members were present.

3. **NERC Antitrust Compliance Guidelines and Public Announcement**

   The NERC Antitrust Compliance Guidelines and public announcement 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 discussed the December 2012 ballot results informing the team that while we had a significant way to go, we were making progress. Draft 2 of PRC-027-1 garnered 33.23 % in the weighted segment approval process – an increase of 10 %. A brief review of the comments revealed that many stakeholders were in agreement with the direction of the drafting team but still had suggestions for improvements.

2. **Respond to comments**

   The SDT began reviewing the preliminary draft responses developed by individual members. three subteams presented their draft responses to Question 9 for the team's approval. This completed the responses to comments.

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

   The drafting team made changes to the standard correlating to adopted stakeholder suggestions. Refer to the attached documents to see responses to comments and revisions to the standard.

4. **Action Items – The following assignments were made:**

   Summary responses for each question (attached pdf of previous Consideration of Comments provided for examples of summary responses for questions):

   Q1 – Bill
   Q2 – Sam and David
   Q3 – Kevin
   Q4 – Jeff
   Q5 – Phil Winston

   Summary of Summaries

   Phil Winston and Al McMeekin

Guidelines and Technical Basis and Rationale Box reviews for all changes:

Requirement 1 – Sam and David
Requirement 2 – Kevin (inclusive of Technical Justification example)
Requirement 3 – Bill
Requirement 4 – Jeff

Incorporate David Cirka's language into examples:

Forrest Brock

Revise figures to include interconnecting bus designations:

Phil Waudby

Review and revise VSLs:

Phil Winston and Al McMeekin

Review and revise all associated documents:

Phil Winston and Al McMeekin

PRC-001-3 issues:

Phil Winston and Al McMeekin

5. **Future meeting(s)**

Due to travel conflicts, no face to face meetings were scheduled. It was decided that all work and questions would be relayed via email. If necessary, a ReadyTalk conference would be held to discuss any disagreement.

6. **Adjourn**

The meeting adjourned at 5:30 p.m. ET on Thursday, January 24, 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.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPC SDT) created a new results-based standard, PRC-027-1, to coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults. This standard incorporates and enhances the coordination aspects of Requirements R3 and R4 from PRC-001-1 (now R2 and R3 of PRC-001-2). The SPC SDT is requesting a posting for stakeholder comments under a 30-day formal comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period with Parallel Successive Ballot	November 2012
Recirculation Ballot	January 2013

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is six 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 six 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 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[p1] **Element**: ~~An~~ A BES Element that electrically joins facilities owned by:
a) separate ~~Functional~~ Registered Entities, or
b) the same Registered Entity~~,~~ that represents multiple functional entity responsibilities- (Distribution Provider, Generator Owner, or Transmission Owner).~~including those Functional Entities that are a part of the same Registered Entity.~~

Protection System Coordination Study: A study that demonstrates existing or proposed Protection Systems operate in the desired 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 Elements, such that ~~the least number of power system Elements are isolated to clear Faults.~~ Protection System components operate in the desired sequence during ~~f~~Faults.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

4.2 Facilities:

Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and 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 focus 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 enhanced 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 Elements, such that the least number of power system Elements are isolated to clear Faults."*

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 address data and data requirements that are included in the proposed Reliability Standard TOP-003-2. The SPC SDT is incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 in a new standard (as recommended by the SPCTF assessment), and focusing on the performance of Protection Systems during Faults. Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) will be retired upon appropriate regulatory approval of the proposed standards PRC-001-3 and PRC-027-1. The SPC SDT recommends 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.

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.

Other Aspects of coordination of Protection Systems addressed by other Projects:[p2]

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 by PRC-006-1 (Project 2007-01 Underfrequency Load Shedding – pending FERC approval) and generator performance during frequency excursions is being addressed by PRC-024-1 in 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 by PRC-024-1 in Project 2007-09, Generator Verification.

- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is being addressed by PRC-019-1 in Project 2007-09.

- Transmission relay loadability is addressed in PRC-023-1 and, pending FERC approval, PRC-023-2.
- Generator relay loadability will be addressed by Phase 2 of Relay Loadability: Generation, in Project 2010-13.2.
- Protective relay response during power swings will be addressed in Phase 3 of Project 2010-13.3, Relay Loadability.
- 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

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

Rationale for R1:

Part 1.1 Protection System Studies are necessary to verify coordination of Protection Systems for existing and new Interconnected Element. The drafting team defines the term “Interconnected Element” as “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.”

Part 1.1.1 The drafting team believes ~~48~~ 60 months is an appropriate period of time for entities to perform the Protection System Studies required where no study exists. The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame.

Part 1.1.2 The drafting team believes that 6 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 deviation at an interconnecting bus, where such conditions may warrant a new Protection ~~System Study~~System Coordination Study, or to technically justify why no such study is required, 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, or to technically justify why no such study is needed. The drafting team believes the timeframe associated with this requirement is contingent upon the project’s scope and schedule. Specifying a time frame for performing studies associated with Requirement R3 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.

Part 1.2 The drafting team believes to properly ensure coordination of Protection Systems associated with Interconnected Element(s), all entities need to share the summary of results of a Protection ~~System Study~~System Coordination Study (~~PSS~~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 ~~PSS~~PSCS performed in accordance with Requirement R1 to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s).

Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by

1.1. Perform a Protection ~~System Study~~System Coordination Study for each of its Interconnected Elements ~~on its System~~ as follows:

1.1.1 Within ~~48~~ 60 calendar months after the effective date of this standard, if no Protection ~~System Study~~System Coordination Study for that Interconnected Element exists.

1.1.2 Within six 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 Part 3.3, or technically justify why such a study is not required.

1.2. Within 90 calendar days after the completion of each Protection System Coordination Study provide to the other owner(s) of the Protection System(s) associated with the

Interconnected Element(s) a summary of the results of each Protection System Coordination Study performed pursuant to this requirement, (including, at a minimum, the Protection Systems ~~protective relay settings~~ reviewed,~~ power system Elements to be isolated, contingencies evaluated,~~ the associated Fault currents used,~~,~~ any issues identified, and any revisions proposed).

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

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

R2. For each ~~Facility associated with an~~ Interconnected Element on its System, the Transmission Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

2.1. At least once every ~~24~~ 60 months:

- perform the activities in Parts 2.1.1 and 2.1.2, or
- ~~2.1.~~ technically justify why fault current does not affect the Protection System coordination.~~:~~

2.1.1 Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a

Rationale for R2: This requires a periodic review of Fault currents at the interconnecting bus and providing to the results to the applicable entities when deviations occur that meet the Requirement R2 criteria. It is important that interconnected 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. These studies are typically performed assuming maximum generation and all Facilities in service. The drafting team determined that 10% was an appropriate point to provide this information based on the fact that Protection Systems are typically set with margins above 10%.

Part 2.1 ~~Short circuit databases are customarily updated annually, so~~ T~~t~~he drafting team believes ~~24~~ 60 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent ~~deviation~~change of the total Fault current at the interconnecting bus. The drafting team believes studies associated with changes that would affect the coordination in less time would be triggered by other requirements in this standard. The drafting team is including this formula to assure a consistent approach is used by each Transmission Owner when calculating the percent ~~deviation~~ change in Fault current values. 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 2.2 The drafting team believes the 30-day time frame is reasonable for providing the Fault current information to the owner(s) of the Protection System(s) associated with the Interconnected Element.

Protection ~~System Study~~System Coordination Study is available per Requirement R1.

2.1.2 Calculate the percent ~~deviation~~ change between the Fault current values (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent Protection ~~System Study~~System Coordination Study and the Fault current values determined pursuant to Requirement R2, Part 2.1.1, using the following equation:

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

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

And: $I_{\cancel{pss}pscs}$ = Fault current value used in the most recent Protection ~~System Study~~System Coordination Study

2.2. Within 30 calendar days after identification where the calculation performed~~,~~ pursuant to Requirement R2, Part 2.1.2~~,~~ indicates a ~~deviation~~ change in either single line to ground or 3-phase Fault current of 10% or greater, provide each owner of the Protection System associated with the Interconnected Element the updated Fault current values (I_{scs}[p3]).

M3. Acceptable evidence for Requirement R2, Part 2.1 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 that identifies the percent ~~deviation~~ change from the most recent Protection ~~System Study~~System Coordination Study Fault current values determined by the ~~formula~~equation. Acceptable evidence of technical justification for not performing a short circuit study as specified in Requirement R2, Part 2.1 could be documented engineering analyses or assessments that demonstrate changes in Fault current do not impact any aspects of coordination.

Rationale for R3: This requires the transfer of appropriate information to the entities associated with each Interconnected 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 Protection System Studies by ensuring that the information is provided to the owner(s) of the Protection Systems associated with Interconnected Element(s). The drafting team believes that information about any change (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 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 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 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 Protection ~~System Study~~System Coordination Study, as required in Parts 1.1.1, 1.1.2, and 1.1.3. 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.

M4. Acceptable evidence for Requirement R2, Part 2.2 is dated documentation (hard copy or electronic file formats) that the updated Fault current values (I_{scs}), ~~along with documentation (hard copy or electronic file formats) for Requirement R2, Part 2.2~~ was provided within the specified timeframe to each owner of the Protection System associated with the Interconnected Element.

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 Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

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

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

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.

M7. Acceptable evidence for Requirement R3, Part 3.3 is

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with Interconnected Elements confirm that the Protection System(s) applied 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 Elements to review the summary results of a Protection ~~System Study~~System Coordination Study. If any issues are identified that require changes then respond whether further action is required.

Part 4.2 The drafting team believes that proposed modifications (including project schedules) to Facility changes associated with the Interconnected Element, as described in Requirement R3, Part 3.1, must be communicated and accepted prior to the in-service date. Acceptance assures that the coordination of Protection Systems dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the changes made was provided within 30 calendar days.

R4. Each 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, respond as to whether any coordination issues were identified through a review of the summary results of a Protection System Coordination Study and if any further action is required~~review the summary results of a Protection System Study~~~~System Coordination Study~~, as described in Requirement R1, Part 1.2, and ~~respond as to whether further action is required.~~

4.2. Prior to implementing any ~~planned~~ proposed change(s) associated with Requirement R3, Part 3.1, receive confirmation that the other owner(s) of each Facility associated with the affected Interconnected Element ~~accept any resulting~~haves completed a review of the Protection System(s) changes and any identified coordination issues were resolved.

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.

M9. Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating, prior to implementation of any planned Protection System(s) changes, that ~~confirmation of acceptance was achieved~~a review of the Protection System(s) changes ~~has been~~was completed and any identified coordination issues were resolved ~~prior to implementation of any planned Protection System(s) changes~~.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

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~~ Each Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System associated with an ~~at an~~ Interconnected Facility shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4, and Measures M1 through M9, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System at a Facility associated with an Interconnected 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 Study~~System Coordination Study on an Interconnected Element per 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 Study~~System Coordination Study at an interconnecting bus per R1, Part 1.1.2, or documented 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 Study~~System Coordination Study results in accordance with R1, Part 1.2, but was late by 10 calendar	The responsible entity performed a Protection ~~System Study~~System Coordination Study on an Interconnected Element per R1, Part 1.1.1, but was late by more than 30 calendar days. OR The responsible entity performed a Protection ~~System Study~~System Coordination Study at an interconnecting bus per R1, Part 1.1.2, or documented why a study was not required, but was late by more than 30 calendar days but less than or equal to 40 calendar days. OR The responsible entity provided the Protection ~~System Study~~System Coordination Study results in accordance with R1, Part 1.2, but	The responsible entity performed a Protection ~~System Study~~System Coordination Study at an interconnecting bus per R1, Part 1.1.2, or documented why a study was not required, but was late by more than 40 calendar days but less than or equal to 50 calendar days. OR The responsible entity provided the Protection ~~System Study~~System Coordination Study results in accordance with R1, Part 1.2, but was late by more than 20 calendar days but less	The responsible entity performed a Protection ~~System Study~~System Coordination Study at an interconnecting bus per R1, Part 1.1.2, or documented why a study was not required but was late by more than 50 calendar days. OR The responsible entity provided the Protection ~~System Study~~System Coordination Study results in accordance with R1, Part 1.2, but was late by more than 30 calendar days.

<table>
<tr><th rowspan="2">R #</th><th rowspan="2">Time Horizon</th><th rowspan="2">VRF</th><th colspan="4">Violation Severity Levels</th></tr>
<tr><th>Lower VSL</th><th>Moderate VSL</th><th>High VSL</th><th>Severe VSL</th></tr>
<tr><td></td><td></td><td></td><td>days or less.</td><td>was late by more than 10 calendar days but less than or equal to 20 calendar days.</td><td>than or equal to 30 calendar days.</td><td>OR
The responsible entity failed to perform a Protection ~~System Study~~System Coordination Study on an Interconnected Element per R1, Parts 1.1.1, 1.1.2, or 1.1.3, or failed to technically justify~~document~~ why a study was not required.
OR
The responsible entity failed to provide Protection ~~System Study~~System Coordination Study results in accordance with R1, Part 1.2.</td></tr>
<tr><td>R2</td><td>Long-term Planning</td><td>Medium</td><td>The Transmission Owner performed a short circuit study, as described in R2, Part 2.1, but was late by less than or equal to 30 calendar days.</td><td>The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to ~~40~~ 60 calendar days.</td><td>The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than ~~40~~ 60 calendar days but less than or equal to ~~50~~ 90 calendar days.</td><td>The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than ~~50~~ 90 calendar days.
OR
The Transmission Owner failed to perform a short circuit study, as</td></tr>
</table>

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 Element the changes in Fault currents, as described in R2, Part 2.2, 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 Element the changes in Fault currents, as described in R2, Part 2.2, 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 Element the changes in Fault currents, as described in R2, Part 2.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	described in R2, Part 2.1. OR The Transmission Owner failed to calculate the percent ~~deviation~~ change between the Fault currents, according to the formula designated in R2, Part 2.1. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element the changes in Fault currents, as described in R2, Part 2.2, 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 Element the changes in Fault currents.
R3	Operations Planning	Medium				The responsible entity failed to provide information to 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 per R3, Part 3.2, but was late by 10 calendar days or less. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by 10 calendar days or less.	The responsible entity provided the requested information per 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 required information identified in 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 per 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 required information identified in R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	Interconnected Element for any proposed change identified in R3.1. OR The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the requested information.
R4	Operations Planning	Medium	The responsible entity confirmed acceptance of the summary results of the Protection ~~System Study~~System Coordination Study per R4, Part 4.1, but was late by 10 calendar days or less.	The responsible entity confirmed acceptance of the summary results of the Protection ~~System Study~~System Coordination Study per R4, Part 4.1, but was late by more than 10 calendar days but less than or equal to 20	The responsible entity confirmed acceptance of the summary results of the Protection ~~System Study~~System Coordination Study per R4, Part 4.1, but was late by more than 20 calendar days but less than or equal to 30	The responsible entity confirmed acceptance of the summary results of the Protection ~~System Study~~System Coordination Study per R4, Part 4.1, but was late by more than 30 calendar days.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				calendar days.	calendar days.	OR The responsible entity failed to confirm acceptance of the summary results of the Protection ~~System Study~~System Coordination Study per R4, Part 4.1. OR The responsible entity failed to confirm acceptance of the planned changes pursuant to R4, Part 4.2 prior to implementation of those changes.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Purpose:

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

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

Requirement R1:

This requirement directs the performance of Protection System Studies for every Interconnected Element to verify coordination of existing Protection Systems where no recent study exists or when Facility configuration or Fault current ~~deviations~~ changes of 10% or more have occurred. In developing the language to define Protection ~~System Study~~System Coordination Study, 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 Study~~System Coordination Study for use within the PRC-027-1 Reliability Standard as:

> "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."

Protection System Studies 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 Protection System Studies 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.

The drafting team believes applicable entities should have a documented Protection ~~System Study~~System Coordination Study for each Interconnected Element to validate the Protection Systems associated with those Interconnected Elements perform in a manner consistent with the purpose of this Standard. Additionally, the drafting team believes that 48 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 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 Protection System Studies must be completed under the following two circumstances:

1. After notification of an identified 10% or greater ~~deviation~~ change in Fault current, the notified entities must perform a new Protection ~~System Study~~System Coordination Study of the Interconnected 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 ~~deviation~~ change in Fault current may not necessitate a new Protection ~~System Study~~System Coordination Study 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 six-month time frame associated with this requirement represents a reasonable period to perform the studies that are required after identification by the 24-month Fault current review.

2. After proposing or being notified of a change at a Facility associated with the Interconnected Element, entities must perform a new Protection ~~System Study~~System Coordination Study, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the proposed change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new Protection ~~System Study~~System Coordination Study 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 this requirement is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3 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 R4, Part 4.2.

Requirement R1, Part 1.2 directs the entity performing the Protection ~~System Study~~System Coordination Study to provide a summary of the study results to the affected Interconnected Element owner(s). As guidance, the drafting team lists the following inputs and results of a Protection ~~System Study~~System Coordination Study that may 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 were reviewed for coordination of protective relays as part of the study including the contingencies used in the evaluation.
2. Data used to determine Fault currents in performing the study, along with 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 Protection System Studies 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 Protection ~~System Study~~System Coordination Study may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates a periodic review of Fault currents or a technical justification stating why fault current does not affect the Protection System coordination of that Interconnected Element. The short circuit study ~~and~~ includes the ~~calculation of the percent deviation between the~~ Fault current values used to calculate the percent change between the ~~in the~~ most recent Protection ~~System Study~~System Coordination Study and the present Fault current values indicated by the short circuit study performed pursuant to this requirement. This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.2. These studies are typically performed assuming maximum generation and all Facilities in service.

~~Polling of drafting team membership and various protection engineering committees indicates that short circuit databases are customarily updated annually. Based on this information,~~ T~~t~~he drafting team believes that ~~requiring a 24~~60~~-~~ months is an appropriate ~~period~~interval~~ic~~ for reviewing ~~of~~ Fault currents or technically justifying why fault currents do not affect the Protection System coordination of a specific Interconnected Element. ~~provides entities additional flexibility to schedule and perform these studies and calculate the percent deviation, as described in Requirement R2, Part 2.1.~~ The drafting team believes studies associated with changes that would affect the coordination in less than ~~24~~ 60 months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.2 further directs the Transmission Owner to, within 30 calendar days, inform each owner of the Facility associated with the Interconnected Element when short circuit studies indicate that 10% ~~deviations~~ changes in Fault current have occurred at the interconnecting bus(s). The drafting team believes the 30-day time frame associated with this requirement is reasonable for providing the Fault current information to the interconnected entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the ~~Functional~~ functional ~~Entity~~ entity responsible for performing the Fault current 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 change to provide the details to the other affected entities of the Interconnected 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 Protection System Studies 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 Protection ~~System Study~~System Coordination Study of the Facility associated with the Interconnected Element; e.g., the addition of a large autotransformer bank or generator not directly associated with the Interconnected 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 Protection ~~System Study~~System Coordination Study or, absent such agreement, within 30 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.

Additionally, this requirement includes a provision for providing details associated with changes to the previously agreed-upon coordination when 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:

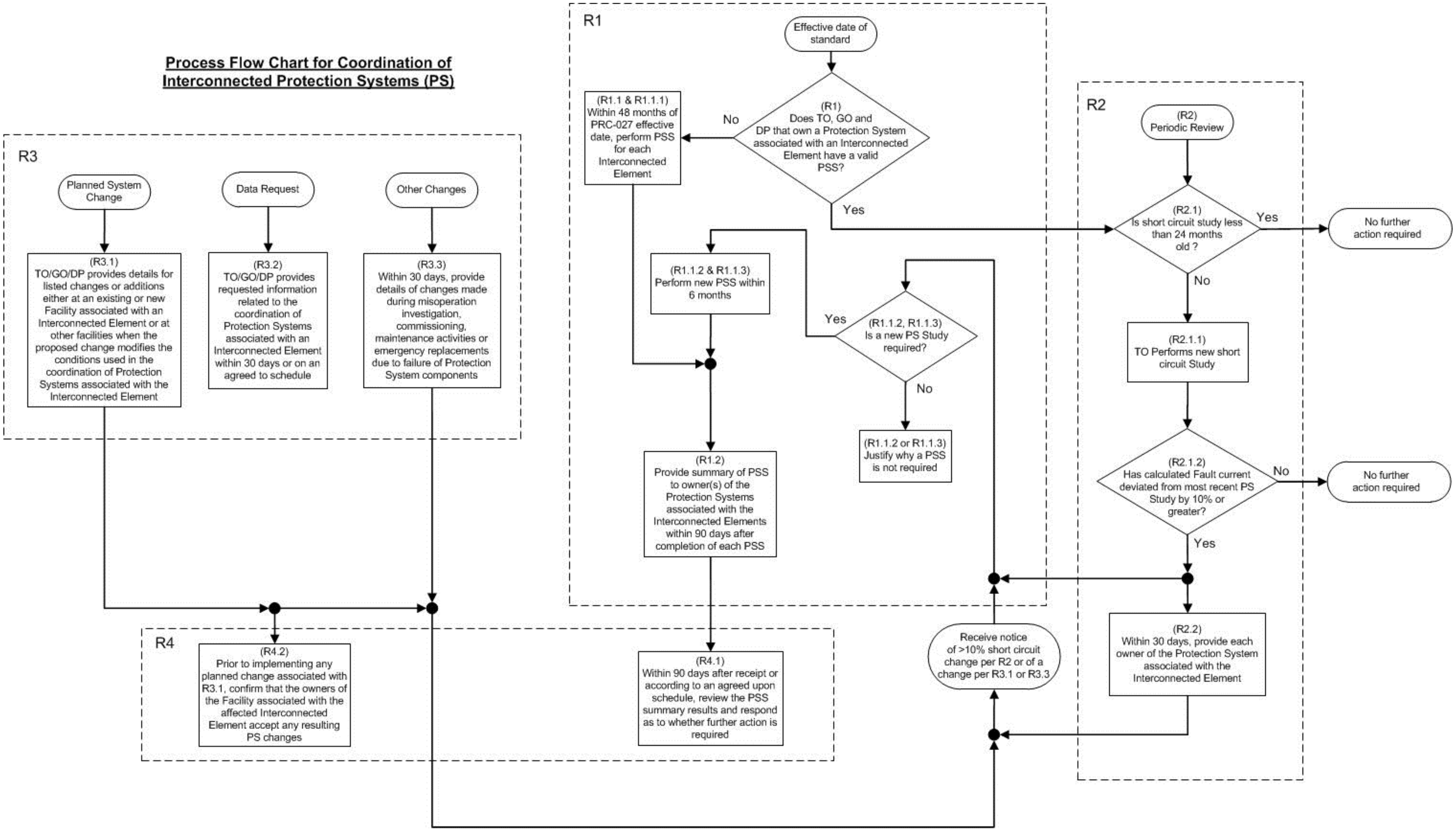
The reliability objective of this requirement is to bring the process of Protection System coordination full circle by gaining the confirmation of interconnected entities that their

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 Protection ~~System Study~~System Coordination Study, as described in Requirement R1, Part 1.2; or absent acceptance propose revisions to achieve acceptable results. The drafting team believes 90 calendar days after receipt of the results of a Protection ~~System Study~~System Coordination Study provides a reasonable time for the owners of Facilities to resolve differences and confirm acceptance that their Protection Systems are coordinated.

Requirement R4, Part 4.2 directs entities to confirm that planned changes described in Requirement 3.1 are acceptable prior to the in-service date of those changes. The purpose of this requirement is to assure the effects that planned changes have on Protection Systems at a Facility associated with the affected Interconnected Element have been considered by all affected entities.

Process Flow Chart: Below is a complete representation of the process, including the relationships between requirements:



Example Process

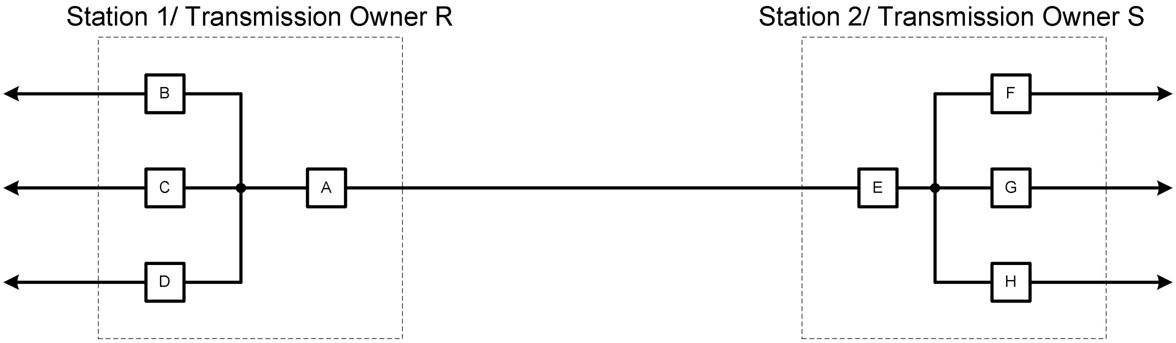
An example of the interaction between entities required to gather the information to perform an accurate study is below.

- The initiating entity (Entity A) will contact the interconnected entity (Entity B) and request up-to-date Protection System information.
- 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 Protection ~~System Study~~System Coordination Study 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 Protection ~~System Study~~System Coordination Study.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, confirm agreement that coordination is achieved.
    - 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.
- Documentation of the final agreement is required prior to implementation of planned changes.

Diagrams[p4]

Introduction: The diagrams below are intended to provide guidance related to the purpose of this standard between owners of Facilities associated with the affected Interconnected Element. After the reviews and prior to implementation of the changes, the owners must reach agreement on the final settings to achieve coordination of the Protection Systems. (Generator Protection for Dave) (Fault Study completed Owner)

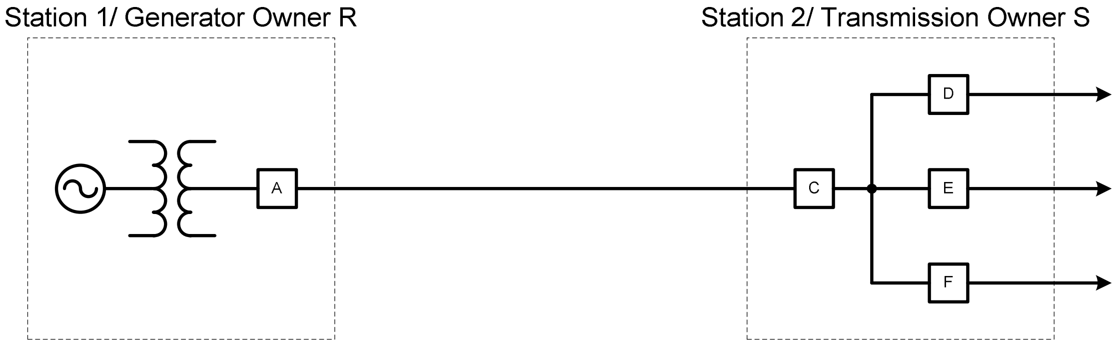
Figure 1



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

Example: For the purposes of conducting the Protection ~~System Study~~System Coordination Study 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 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

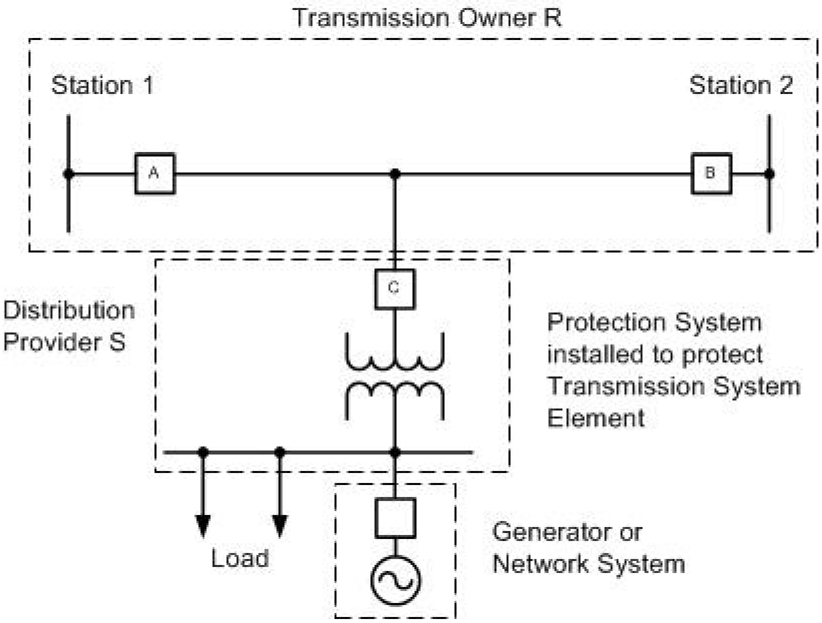


In Figure 2 above, the Interconnected Element between the Transmission Owner and the Generator Owner is the transmission line or bus between Breakers A and C.

Note: Depending on the actual configuration and/or ownership, breaker A may or may not exist as a HS unit breaker or a line breaker

Example: For the purposes of conducting the Protection ~~System Study~~System Coordination Study associated with the Facilities in Figure 2, 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, Generation 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 Element between the Transmission Owner and the Distribution Provider is the transmission line or tap between the line and Breaker C.

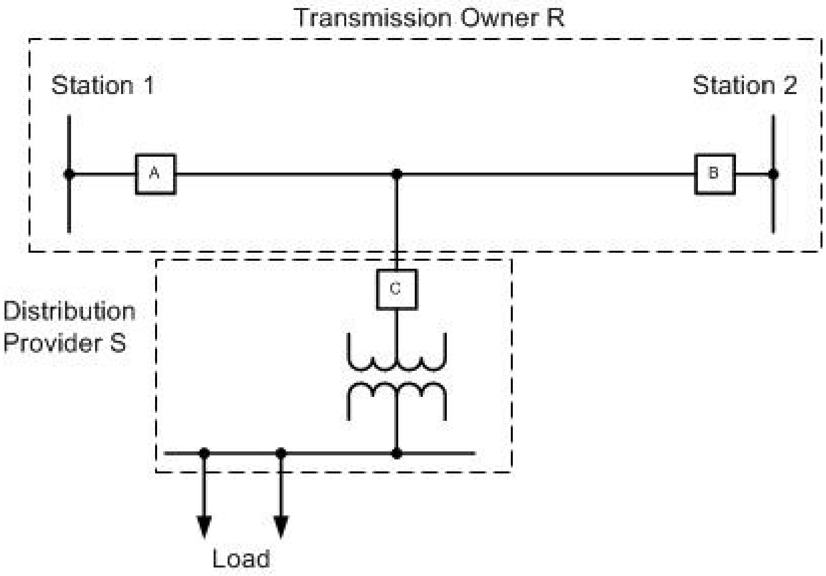
Example: For the purposes of conducting the Protection ~~System Study~~System Coordination Study associated with the Facilities in Figure 3, Transmission Owner R is to review the Protection System settings associated with Line Breaker C (provided by Distribution Provider S) for coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2.

Notes:

A Protection ~~System Study~~System Coordination Study is required per this standard for this example if a Protection System at the Distribution Provider's substation is ~~designed to~~ installed for the purpose of detecting Faults on BES Elements.~~detect Faults on the BES Transmission System.~~[p5]

~~“~~Protection Systems installed for the purpose of detecting Faults on BES Elements~~to detect faults on the BES Transmission System”~~ are not inclusive of those relays that may operate for such faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.). As an example, reverse power relays are often installed to detect situations where the transmission source becomes de-energized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a Fault on a BES Element, they are not ~~“~~installed for the purpose of detecting Faults on BES Elements~~to detect faults on the BES Transmission System~~.~~”~~

Figure 4



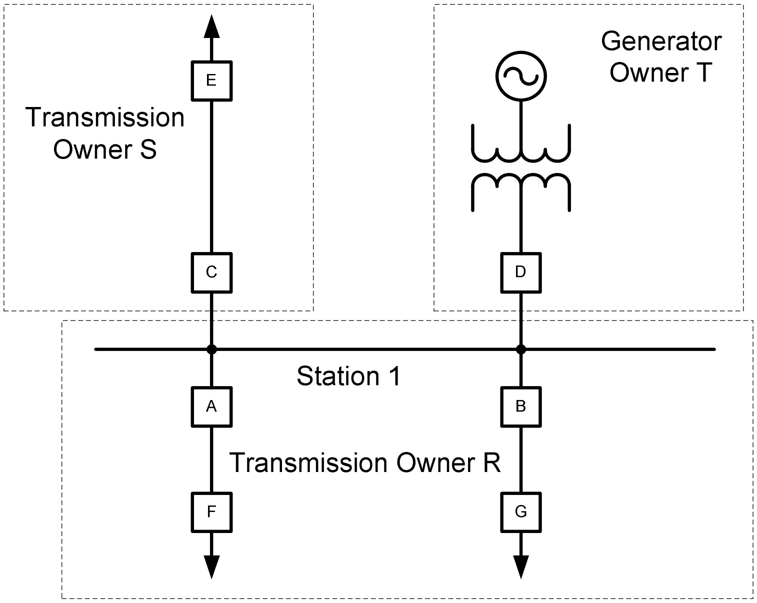
In Figure 4 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line or tap between the line and Breaker C.

Note: No specific Protection ~~System Study~~System Coordination Study is required per this standard for this example since the Protection System at the Distribution Provider's substation is not designed to protect BES transmission system Elements[p6].

Figure 5

Transmission/Generation Facility with Multiple Owners

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



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

Example: For the purposes of conducting the Protection ~~System Study~~System Coordination Study associated with the Facilities in Figure 5:

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

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Consideration of Comments

Project 2007-06 System Protection Coordination

The System Protection Coordination Drafting Team thanks all commenter's who submitted comments on the 1st draft of the standard for Protection System Coordination for Performance During Faults. These standards were posted for a 45-day public comment period from May 21, 2012 through July 5, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 76 sets of comments, including comments from approximately 198 different people from approximately 139 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/System_Protection_Project_2007-06.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received

Definitions

The drafting team added the following sentence to the standard to specify that the definitions will not be added to the NERC Glossary of Terms. "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 Glossary of Terms:"

The drafting team modified the previous definition of Interconnected Facilities to 'Interconnected Element' defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity."

Purpose

The drafting team modified the purpose statement based on comments related to two main issues: (1) the inclusion of the phrase '…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards', and (2) the inclusion of the phrase '… remove

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

from service only those Elements…'. The purpose now reads: To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.

Applicability

The Applicability was modified as follows:

4.2 Facilities: Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.

Requirements

The time frame for Requirement R1, Part 1.1.1 was increased to forty-eight calendar months to allow entities with large numbers of Interconnected Elements enough time to complete the Protection System Studies. Additionally, changes were made to not exclude studies performed prior to June 18, 2007. Requirement R1, Part 1.1.1 now reads: (Part 1.1 Perform a Protection System Study)…"Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists."

The drafting team modified Requirement R1, Part 1.1.2 to be consistent with the Fault location referenced in Requirement R2, Parts 2.1 and 2.2 such that it now reads: "Within six 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."

The drafting team modified Requirement R1, Part 1.1.3 for clarity. It now reads: "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 Part 3.3, or technically justify why such a study is not required."

The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."

The drafting team reworded Requirement R2 to read as follows: "For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall:"

The drafting team modified Requirement R2, Part 2.1 to provide clarity as to where the Fault should be applied. Requirement R2, Part 2.1.1 now reads: At least once every 24 months: "Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."

The equation stated in Requirement R2, Part 2.1.2 was modified to replace "V" with "I".

The drafting team modified Requirement R2, Part 2.2 to provide clarity and to change "notify" to "provide" such that it now reads: "Within 30 calendar days after identification where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates a deviation in Fault current of 10% or greater, provide each owner of the Protection System associated with the Interconnected Element the updated Fault current values (Iscs)."

The drafting team modified Requirement R3 for clarity and moved the examples into Measure M5 such that it now reads: "Acceptable evidence may include, but is not limited, a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) in hard copy or electronic file formats as identified in the bulleted list for Requirement R3, Part 3.1 was provided to each responsible entity connected to the same Interconnected Element."

The drafting team modified Requirement R3, Part 3.1 for consistency with changes to other requirements, the addition of the examples, combining the second and third bullets, and clarity. It now reads: "Details for any change or additions 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 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 change 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

The drafting team modified Requirement R3, Part 3.2 for clarity. It now reads: "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."

The drafting team combined the Requirement R3 Part 3.3 subparts 3.3.1 and 3.3.2 into the main body of the Requirement R3, part 3.3 which now reads: "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."

The drafting team removed the term “confirm agreement” from Requirement R4, Part 4.1 and revised it to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”

The drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”

The drafting team removed Requirement R4, Part 4.3.

Measures

The drafting team modified all the measures to be consistent with the revised requirements.

Evidence Retention

The drafting team modified the language for consistency.

VSLs and Time Horizon

The drafting team made no changes to the VRFs; however, the following changes were made to the VSLs:

- For Requirement R1, Part 1.1.2, the time period for tardiness in the ‘Lower’ VSL was lengthened from 10 days to 30 days.

The drafting team added Long-term Planning to the Time Horizon for Requirement R3.

Guidelines and Technical Basis

Complementary changes were made to the Guidelines and Technical Basis corresponding to all changes to the standard.

The drafting team added the following to the description of a Protection System Study in the “Guidelines and Technical Basis”: “System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions.”

The drafting team revised the description relating to Figure 3 in the “Guidelines and Technical Basis” to clarify that only the Distribution Provider’s Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard. The drafting team modified Figure 3 to indicate that the source could be a generator or a network system.

The drafting team modified the text associated with each Figure to identify the Interconnected Elements.

The drafting team modified the process flow chart to be consistent with the requirements.

Unresolved Minority Views

- Several commenters felt that the Transmission Planner, Planning Authority, Transmission Operator and/or Generator Operator should be included because those entities were identified as providing the Protection System Studies and/or system modeling services for the owners. An example response to these comments was as follows: The SDT believes that the owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others.
- Several commenters disagreed with the Distribution Provider being included. The SDT responses indicated that the inclusion of Distribution Providers was appropriate if the Distribution Provider owned Protection Systems that require coordination with other owners for isolating generation and Transmission Faults.
- A few commenters disagreed with the 10% deviation trigger. The drafting team recognizes there are variations of margins used throughout the industry; however, believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.
- A few commenters had concerns with the 30-day time frame in Parts 3.2 and 3.3 while other commenters wanted them eliminated. The drafting team explained that they believed the 30-day time frame is appropriate and declined to make the change.
- Some commenters wanted to remove reference to schedules in the requirements. The drafting team reinforced that they believe the sharing of project schedules is a necessary communication between entities.
- A few commenters expressed concerns that there is redundancy between this draft standard and several FAC standards. The drafting team stated their belief that these concerns were not applicable.
- Several commenters expressed a desire to see the standard drafting team develop and include a conflict resolution process for situations where mutual agreement cannot be reached. The drafting team responded with the following: The drafting team believes that any conflict resolution should be handled through normal company practices. Note that the drafting team changed from agreement to confirm acceptance.
- Some commenters wanted the drafting team to further modify PRC-001-2 by adding a Measure for Requirement R1 or retire the standard. This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, “The drafting team recommends 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”. Note: PRC-001-1 Requirement 1 never had an associated measure.

- Some commenters expressed concern over the number of time frames associated with the coordination process and the burden of documentation. The drafting team believes the assigned time frames and documentation are appropriate and necessary and declined to make any changes.
- A few commenters wanted time frames to be established for Requirement R1, Part 1.1.3. The drafting team reiterated that there is not a single time frame that would be appropriate for every project and chose not to modify the standard.

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	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	MRO	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6
4.	Michael Crowley	Dominion Virginia Power	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jonathan Hayes	Southwest Power Pool NERC Reliability Standards Development Team	X	X		X						

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	Sean Simpson	Board of Public Utilities of Kansas City, Kansas	SPP	NA

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

4.	Willy Haffecke	City Utilities of Springfield	SPP	1, 4
5.	Fred Ipock	City Utilities of Springfield	SPP	1, 4

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Michael Jones	National Grid USA / Niagara Mohawk	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Schiavone	Niagara Mohawk (National Grid)	NPCC	3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light	RFC	1
2.	Mark Godfrey	Pepco Holdings	RFC	1
3.	Alvin Depew	Pepco	RFC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Sasa Maljukan	Hydro One	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc.	NPCC	1
2.	Paul Difilippo	Hydro One Networks Inc.	NPCC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jose Landeros	IID	WECC	1, 3, 4, 5, 6
2.	Lupe Ontiveros	IID	WECC	1, 3, 4, 5, 6

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean	Bender	WECC	1
2.	Fran	Halpin	WECC	5
3.	Erika	Doot	WECC	3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	L. Raczkowski	FE	RFC	
2.	J. Detweiler	FE	RFC	

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

3.	B. Orians	FE	RFC	
4.	D. Hohlbaugh	FE	RFC	

				1	2	3	4	5	6	7	8	9	10
10.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Shawn T. Abrams	Santee Cooper	SERC	1
2.	Bridget Coffman	Santee Cooper	SERC	1
3.	Rene' Free	Santee Cooper		1

				1	2	3	4	5	6	7	8	9	10
11.	Group	Kent Kujala	Detroit Edison			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Barbara Holland			3, 4, 5
2.	Karie Barczak			3, 4, 5
3.	David Szulczewski			3, 4, 5

				1	2	3	4	5	6	7	8	9	10
12.	Group	Steve Alexanderson P.E.	Western Small Entity Comment Group			X	X					X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dale Dunckel	Okanogan PUD	WECC	1
2.	Ronald Sporseen	Blachly-Lane Electric Cooperative	WECC	3
3.	Ronald Sporseen	Central Electric Cooperative	WECC	3
4.	Ronald Sporseen	Consumers Power	WECC	1, 3
5.	Ronald Sporseen	Clearwater Power Company	WECC	3
6.	Ronald Sporseen	Douglas Electric Cooperative	WECC	3
7.	Ronald Sporseen	Fall River Rural Electric Cooperative	WECC	3
8.	Ronald Sporseen	Northern Lights	WECC	3
9.	Ronald Sporseen	Lane Electric Cooperative	WECC	3
10.	Ronald Sporseen	Lincoln Electric Cooperative	WECC	3
11.	Ronald Sporseen	Raft River Rural Electric Cooperative	WECC	3
12.	Ronald Sporseen	Lost River Electric Cooperative	WECC	3
13.	Ronald Sporseen	Salmon River Electric Cooperative	WECC	3
14.	Ronald Sporseen	Umatilla Electric Cooperative	WECC	3
15.	Ronald Sporseen	Coos-Curry Electric Cooperative	WECC	3
16.	Ronald Sporseen	West Oregon Electric Cooperative	WECC	3
17.	Ronald Sporseen	Pacific Northwest Generating Cooperative	WECC	3, 8
18.	Ronald Sporseen	Power Resources Cooperative	WECC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid		1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
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.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co.of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6

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

7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC	MRO	1, 3, 5, 6

15.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates					X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
2.			WECC	5
3.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
4.			NPCC	6
5.			SERC	6
6.			SPP	6
7.			RFC	6
8.			WECC	6

16.	Group	Joe Spencer	SERC Protection and Control Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Andrew Monroe	Georgia Power (So. Co.)	SERC	
2.	Paul Nauert	Ameren	SERC	
3.	Charlie Fink	Entergy	SERC	
4.	Russ Evans	SCANA	SERC	
5.	Steve Edwards	Dominion/Va Power	SERC	
6.	Jay Farrington	PowerSouth	SERC	
7.	John Miller	GTC	SERC	
8.	Ernesto Paon	MEAG Power	SERC	
9.	Phil Winston	Georgia Power (So. Co.)	SERC	
10.	Bridget Coffman	Santee Cooper	SERC	
11.	George Pitts	TVA	SERC	

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<tr><th colspan="2">Group/Individual</th><th>Commenter</th><th>Organization</th><th colspan="10">Registered Ballot Body Segment</th></tr>
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<tr><td>12.</td><td>David Greene</td><td>SERC</td><td>SERC</td><td></td></tr>
<tr><td>13.</td><td>Joe Spencer</td><td>SERC</td><td>SERC</td><td></td></tr>
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<tr><td>17.</td><td>Group</td><td>Jennifer Eckels</td><td>Colorado Springs Utilities</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td>X</td><td></td><td></td><td></td><td></td></tr>
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<tr><td>1.</td><td>Paul Morland</td><td></td><td>WECC</td><td>1</td></tr>
<tr><td>2.</td><td>Charles Morgan</td><td></td><td>WECC</td><td>3</td></tr>
<tr><td>3.</td><td>Lisa Rosintoski</td><td></td><td>WECC</td><td>6</td></tr>
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<tr><td>18.</td><td>Group</td><td>Charles Yeung</td><td>ISO RTO Council SRC</td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
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<tr><td>1.</td><td>Gary DeShazo</td><td>CAISO</td><td>WECC</td><td></td></tr>
<tr><td>2.</td><td>Steve Myers</td><td>ERCOT</td><td>ERCOT</td><td></td></tr>
<tr><td>3.</td><td>Matt Goldberg</td><td>ISONE</td><td>NPCC</td><td></td></tr>
<tr><td>4.</td><td>Bill Phillips</td><td>MISO</td><td>MRO</td><td></td></tr>
<tr><td>5.</td><td>Greg Campoli</td><td>NYISO</td><td>NPCC</td><td></td></tr>
<tr><td>6.</td><td>Stephanie Monzon</td><td>PJM</td><td>RFC</td><td></td></tr>
<tr><td>7.</td><td>Don Weaver</td><td>NBSO</td><td>NPCC</td><td></td></tr>
<tr><td>8.</td><td>Ken Gardner</td><td>AESO</td><td>WECC</td><td></td></tr>
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<tr><td>19.</td><td>Group</td><td>Dennis Chastain</td><td>Tennessee Valley Authority</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td>X</td><td></td><td></td><td></td><td></td></tr>
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<tr><td>1.</td><td>Larry Akens</td><td></td><td>SERC</td><td>1</td></tr>
<tr><td>2.</td><td>Ian Grant</td><td></td><td>SERC</td><td>3</td></tr>
<tr><td>3.</td><td>David Thompson</td><td></td><td>SERC</td><td>5</td></tr>
<tr><td>4.</td><td>Marjorie Parsons</td><td></td><td>SERC</td><td>6</td></tr>
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<tr><td>20.</td><td>Group</td><td>Mary Jo Cooper</td><td>GP Strategies</td><td>X</td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
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<tr><td>1.</td><td>Elizabeth Kirkley</td><td>City of Lodi</td><td>WECC</td><td>3</td></tr>
<tr><td>2.</td><td>Angela Kimmey</td><td>Pasadena Water and Power</td><td>WECC</td><td>1, 3</td></tr>
<tr><td>3.</td><td>Douglas Dreager</td><td>Alameda Municipal Power</td><td>WECC</td><td>3</td></tr>
<tr><td>4.</td><td>Ken Dizes</td><td>Salmon River Electric Co-op</td><td>WECC</td><td>1, 3</td></tr>
<tr><td>5.</td><td>Sam Rohn</td><td>California Pacific Electric Co.</td><td>WECC</td><td>3</td></tr>
<tr><td>6.</td><td>Colin Murphey</td><td>City of Ukiah</td><td>WECC</td><td>3</td></tr>
<tr><td>7.</td><td>Michael Knott</td><td>Granite State Electric</td><td>NPCC</td><td>3</td></tr>
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<tr><td>21.</td><td>Group</td><td>David Dockery</td><td>Associated Electric Cooperative, Inc.,</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td>X</td><td></td><td></td><td></td><td></td></tr>
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Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			JRO00088										

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
22.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
2.	John Shaver	Arizona Electric Power Cooperative Inc.	WECC	4, 5
3.	John Shaver	Southwest Transmission Cooperative Inc.	WECC	1
4.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
5.	Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5
6.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
23.	Group	Tim Hinken	Kansas City Power & Light	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Michael Gammon	Kansas City Power & Light	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
24.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
25.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
26.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
27.	Individual	Ed Croft	Operational Compliance	X		X		X					
28.	Individual	John Hagen	Pacific Gas and Electric Company	X		X		X					
29.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
30.	Individual	Michael Falvo	Independent Electricity System Operator		X								
31.	Individual	Thad Ness	American Electric Power	X		X		X	X				
32.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
33.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.				X						
34.	Individual	Anthony Jablonski	ReliabilityFirst										X
35.	Individual	Martin Kaufman	ExxonMobil Research & Engineering	X		X		X		X			
36.	Individual	Jonathan Meyer	Idaho Power Company	X		X							
37.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
38.	Individual	Don Jones	Texas Reliability Entity										X
39.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
40.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X									
41.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
42.	Individual	Chris Scanlon	Exelon	X		X		X	X				
43.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
44.	Individual	David Gordon	Massachusetts Municipal Wholesale Electric Company					X					
45.	Individual	Bill Middaugh	Tri-State G & T	X									
46.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
47.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
48.	Individual	Kirit Shah	Ameren	X		X		X	X				
49.	Individual	John D. Martinsen	Public Utility District No. 1 of Snohomish County	X		X	X	X	X				
50.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP, (Occidental Chemical Corporation)					X					
51.	Individual	John W Miller	Georgia Transmission Corporation	X									
52.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
53.	Individual	Rich Salgo	NV Energy	X		X		X					
54.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
55.	Individual	Mike Weir	Dairyland Power Cooperative	X		X		X					
56.	Individual	Deborah Schaneman	Platte River Power Authority	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
57.	Individual	E Hahn	MWDSC	X									
58.	Individual	Angela P Gaines	Portland General Electric Company	X		X		X	X				
59.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
60.	Individual	Rick Koch	Southern Minnesota Municipal Power Agency				X		X				
61.	Individual	Don Schmit	NPPD	X		X		X					
62.	Individual	Brian Evans-Mongeon	Utility Services								X		
63.	Individual	daniel	mason	X				X					
64.	Individual	Rowell Crisostomo	ATCO Electric	X									
65.	Individual	Bob Thomas and Kevin Wagner	Illinois Municipal Electric Agency				X						
66.	Individual	Rhonda Bryant	El Paso Electric Company	X									
67.	Individual	Steven Powell	Trans Bay Cable	X							X		
68.	Individual	Daniela Hammons	CenterPoint Energy	X									
69.	Individual	Laura Lee	Duke Energy	X		X		X	X				
70.	Individual	Jack Stamper	Clark Public Utilities	X									
71.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
72.	Individual	Brian J Murphy	NextEra Energy Inc	X		X		X	X				
73.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
74.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
75.	Individual	Jian Zhang	TransAlta Centralia Generation LLC					X					
76.	Individual	Pablo OÃ±ate	El Paso Electric	X		X		X	X				

1. **The SDT established the following Purpose for this standard: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards." Do you agree with this Purpose? If not, please provide specific suggestions for changes to the purpose in the comment area.**

Summary Consideration:

The responses were equally split between yes and no. Many negative comments related to the inclusion of the phrase '… while meeting the system performance specified within requirements established in other approved NERC Reliability Standards'. Several comments related to the phrase '… remove from service only those Elements …' due to the fact that some designs include multiple elements within a single protection zone such as bank/bus differential schemes. Suggestions included eliminating 'only' or to add 'as designed'. The Purpose has been modified as follows which addresses the large majority of the negative comments.

Purpose: To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear faults.

Organization	Yes or No	Question 1 Comment
Dominion	No	1. Dominion supports the stated purpose up to the comma. The qualifying language after the comma is ambiguous and not supported in the Requirements of this standard. 2. In the current PRC-001-1 standard the meaning of the term "coordination" has and still is interpreted in two ways. One interpretation is viewed from the technical aspect as "relay coordination" and the second is viewed from an inter-communication aspect as "coordination of information" between entities. The term "coordination" should be removed from the new standard Title and Purpose. a. Recommend changing **Title** to: <u>"Protection System Interconnected Facility Performance During Faults".</u> Also, recommended is to change the **Purpose** to read<u>: "To communicate and exchange Protection</u>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those Elements required to isolate Faults.” In PRC- 027-1, use the term coordination only when referring to the technical aspects of the relay coordination within a Requirement when applicable.
b. Under Purpose, delete: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet ‘the system performance specified within requirements established in other approved NERC Reliability Standards’ and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on yours and others comments, the drafting team removed the phrase: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.”
a. The drafting team agrees that the use of the term “coordination” in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes the use of “coordination” in this standard clearly relates to the technical aspects of relay coordination and respectfully declines to make the suggested changes.
b. Based on yours and others comments, the drafting team removed the phrase: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.”</td></tr>
<tr><td>Southwest Power Pool NERC Reliability Standards Development Team</td><td>No</td><td>We would ask that the team revise the second part of the purpose to lead in with “In accordance with the system performance specified within requirements established in other approved NERC Reliability Standards”   If</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		left as is it reads like you are required to do both the first and second parts of the purpose. This proposed language requires the initial goal of this standard and references that it will do so under the system performance specified in NERC standards.
Response: Thank you for your comment. **Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."**		
Pepco Holdings Inc. & Affiliates	No	1) The language in the Statement of Purpose needs to be reworded. The phrase "remove from service only those elements required to isolate faults" may restrict certain protection practices in widespread use today, where coordination on tapped distribution facilities is achieved via auto-reclosing rather than via coordinated time delays. For example, a BES line (protected by a high speed DCB or POTT pilot scheme) is tapped by a distribution provider as demonstrated in Figure 3 of the Application Guidelines. Very often for distribution taps like these, rather than requiring the distribution provider to establish a costly transmission class pilot scheme terminal at breaker C with communication links to A & B, it is common to let the pilot scheme reach into (but not thru) the transformer at C. For faults in the transformer the high speed transformer relays will operate to trip and lockout breaker C. However, the pilot scheme at A & B will also trip simultaneously. Breaker C will lockout and A & B will auto-reclose to restore the line. Coordination is achieved via auto-reclosing. For faults on the line, A & B will trip via the pilot scheme, and if generation happens to be running either C will trip, or the generator will trip depending on scheme design. Reclosing at A & B would be delayed and / or voltage supervised to ensure generation has been removed prior to auto-reclosing. In the above scenarios since the line tripped for a fault in the transformer, or the generator tripped for a

Organization	Yes or No	Question 1 Comment
		fault on the line, it would violate the requirement to “remove from service only those elements required to isolate faults”. The language used in the proposed definition of Protection System Study is slightly better, using the phrase “demonstrates ... Protection Systems operate in the desired sequence for clearing faults”. 2) The problem here is who determines what is the “desired sequence”? Would a scheme, which is purposely designed as described above and acknowledged by the Transmission Planner and Transmission Operator, be considered to operate in the “desired sequence” for clearing faults? 3) The language in the standard needs to be re-visited to enable these types of protection interfaces with distribution providers having limited generation resources connected downstream. Also, if system reliability was truly an issue for this example, the interconnection should not have been a simple tap on the line, but rather a ring bus should have been established at the interconnection point.

Response: Thank you for your comment.

1. **The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”. The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.**
2. **Determining the “desired sequence” is the purpose of the Protection System Study agreed to by all parties involved.**
3. **The drafting team believes Distribution Providers that own Protection Systems installed for the primary function of detecting Faults on BES Elements should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners. To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: Protection Systems installed at Interconnected Stations for the primary function of detecting Faults on BES Elements. Additionally, the drafting team changed the term “Interconnected Facilities” to Interconnected Elements” defined as follows: “An Element that electrically joins separate Functional Entities, including**

Organization	Yes or No	Question 1 Comment
those Functional Entities that are a part of the same Registered Entity".		
Hydro One	No	1. The goal of this standard is to address co-ordination of protection systems between neighboring entities. To achieve this goal, the efforts should focus on the co-ordination of protections between entities as outlined and described in the NERC SPCS paper "Power Plant and Transmission System Protection Co-ordination - Technical Reference Document (TRD)," dated July 2010. This standard should include the review/study of all protections requiring coordination not the ones dealing with faults only as identified in the above TRD. There should be one comprehensive study/report not spread out into 7-8 standards. If so, there are still protection elements that require coordination that have not been addressed such as: open-phase, loss-of-field, over-excitation, out-of-step, and negative sequence normal unbalance, etc. We don't see how a standard for Protection system co-ordination can rely on other standards to achieve the goal of co-coordinating protections for both Faults and other conditions that challenge co-ordination. 2. The Purpose should be: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate from abnormal system conditions, while meeting the system performance specified within requirements established in NERC TPL Reliability Standards."If the above suggestions are not taken into consideration and the SDT decides to keep the requirements in the current form, the statement"...while meeting the system performance specified within requirements established in other approved NERC Reliability Standards." should be changed to include exact reference to standards or at least group of standards the SDT is referring to.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. **1. As noted in the Background information section, the drafting team believes that other aspects of coordination are or should be covered by other standards and it is appropriate for this standard to be limited to the stated Purpose.** **2. Based on yours and others comments, the drafting team removed the phrase: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.”**		
Imperial Irrigation District (IID)	No	The SDT proposed Purpose is confusing. IID proposes the following Purpose language: “To coordinate Protection Systems for Interconnected Facilities, such that during faults, those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.”
Response: Thank you for your comment. **The drafting team does not see the confusion in the present language and respectfully declines to make the suggested change. The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”.**		
Bonneville Power Administration	No	The purpose of PRC-001-1 was “To ensure system protection is coordinated among operating entities.” With the rewrite of PRC-001 to PRC-027, the standard drafting team has expanded the purpose to specify that only elements required to isolate faults are removed from service and that system performance established in other NERC standards is met. The two additions to the purpose of PRC-027 should be removed for the reasons described below. 1) The statement in the purpose, “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards”, only serves to unnecessarily complicate the purpose statement. BPA recognizes that the NERC standard does not

Organization	Yes or No	Question 1 Comment
		void the requirements of other NERC standards; therefore, there is no need to state in the purpose that other NERC standards must be met. 2) The statement in the purpose, “such that those Protection Systems remove from service only those Elements required to isolate faults”, drastically expands the scope of PRC-027 over PRC-001. With this new purpose, BPA believes this puts NERC in the position of micromanaging how protection systems are applied. Although most protection schemes are intended to remove only the faulted element, it is not necessarily a problem if additional elements are removed, and there might even be reasons to remove additional elements. In some cases it might be significantly less expensive to design a scheme that allows the removal of additional elements. Protection engineers need to have the flexibility to apply protection schemes that meet the requirements of the project at hand. Creating standards with absolute requirements on how protection schemes are applied and set will eliminate the flexibility necessary to implement effective and efficient protection schemes. The Standard Drafting Team (SDT) does not have the ability to foresee all possible protection scenarios, and to create a standard whose purpose is to remove from service only those elements required to isolate faults will create unnecessary expense and difficulty. BPA strongly recommends that the statement “such that those Protection Systems remove from service only those Elements required to isolate faults” be removed from the purpose and that the standard be modified to eliminate this requirement.

Response: Thank you for your comment.

1. **Based on yours and others comments, the drafting team removed the phrase: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.”**
2. **The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such**

Organization	Yes or No	Question 1 Comment
that the least number of power system Elements are isolated to clear Faults". The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.		
FirstEnergy	No	We do not believe the phrase "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" is needed and may be confusing to the reader.
Response: Thank you for your comment. **Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."**		
Santee Cooper	No	It would probably be good to avoid using the term "coordination" as it can be considered as having two meanings, either the "coordinating" of the exchange of the data or the "coordinating" of the actual protective devices. Coordination should be taken out of the title and the purpose. "To Coordinate Protection Systems" could be changed to "To communicate and exchange Protective System data..." in the Purpose. The title could be changed to "Protection System Interconnected Facility Performance during faults"
Response: Thank you for your comment. **The drafting team agrees that the use of the term 'coordination' in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.**		
Detroit Edison	No	It is suggested that ". . . the system performance specified within requirements established in other approved NERC Reliability Standards" be specified so that what needs to be met is clear.
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td>Western Small Entity Comment Group</td><td>No</td><td>The language “...remove from service only those Elements required to isolate Faults...” is problematic. Taken literally; only the faulted Element may be isolated, and any adjoining buswork or lines (separate Elements) must remain energized; even the result is no change in the loss of load or capacity. We suggest ““To coordinate existing Protection Systems...” to ensure that this is not interpreted as a construction standard requiring additional Protection Systems.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”. The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.</td></tr>
<tr><td>PPL Corporation NERC Registered Affiliates</td><td>No</td><td>PRC-027 appears to have been written exclusively for vertically integrated power companies, and there is no justification for making the proposed standard applicable to independent GOs. The only role an independent GO fulfills in isolating faults is to trip the breaker if the generator or GSU has a problem; everything involving sequencing is in the Transmission Owner’s (TOs) or Distribution Providers (DPs) system. Independent GOs are owned by separate legal entities than the applicable TO or Distribution Provider [DP] to which they are interconnected. Such GOs do not have the capability to perform the type of TO/DP system studies that appear to be contemplated by the SDT. The actions required of independent GOs should be to perform Protection System maintenance and supply data to other applicable entities, per existing standards PRC-005-1 and PRC-001-1.1, respectively.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that the Owner of the Protection System is responsible for ensuring its Protection Systems are coordinated with others. It is acknowledged that in many cases, the majority of the work associated with this task will fall on</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
the Transmission Owner; however, the coordination of some Protection Systems owned by Generator Owners installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included.		
SERC Protection and Control Subcommittee	No	a) Recommend under Purpose, deleting: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet 'the system performance specified within requirements established in other approved NERC Reliability Standards' and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003R1.3.7 already requires the entity to "demonstrate that system performance meets its Table 1 for Category C contingencies" (TPL-001, -002 have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1. b) The term "coordination" should be removed from the new standard Title and Purpose. Recommend changing Title to "Protection System Interconnected Facility Performance during Faults". Also recommended is to change the Purpose to read "To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those Elements required to isolate Faults." In PRC 027, using the term coordination should only be referenced when referring to the technical aspects of the relay coordination within a requirement when applicable. (In the current PRC 001 standard the meaning of the term "coordination" has, and still is, interpreted in two ways. One interpretation is viewed from the technical aspect as "relay coordination" and the second is viewed from an inter-communication aspect as "coordination of information" between

<table>
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<tr><td></td><td></td><td>entities).</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
a. Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".
b. The drafting team agrees that the use of the term 'coordination' in PRC-001 did result in multiple meanings and potential confusion. The SDT believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.</td></tr>
<tr><td>ISO RTO Council SRC</td><td>No</td><td>Is the intent of the coordination that is expected limited only to those protection systems related to intertie facilities between facilities owners? Or is the intent of the proposed standard to require coordination of protection systems to take into account outage and/or operating conditions between facilities owners beyond the immediate intertie facilities? In other words is this coordination requirement expected to be applied to relays that may not be directly involved in protection of intertie equipment?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The intent of this standard is focused on those Protection Systems directly associated with the Facility Interconnections. However, as noted in R.3.1 it is recognized that there may be changes or additions 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).</td></tr>
<tr><td>Tennessee Valley Authority</td><td>No</td><td>a) The term "coordination" should be removed from the new standard Title and Purpose. Recommend changing Title to: "Interconnected Facility Protection System Performance During Faults". Also recommend changing the Purpose to read: "To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those elements required</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		to isolate faults." b) Recommend under Purpose, deleting: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” as it is superfluous and could cause duplicative or conflicting work. The purpose without this clause is clear, concise, and consistent with the rest of the 1st draft of this standard. The resulting coordinated Protection System must meet ‘the system performance specified within requirements established in other approved NERC Reliability Standards’ and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003 R1.3.7 already requires the entity to “demonstrate that System performance meets its Table 1 for Category C contingencies” (TPL-001, -002 have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1. c) In PRC 027, the term "coordination" should only be referenced when referring to the technical aspects of the relay coordination within a Requirement when applicable. (In the current PRC 001 standard the meaning of the term “coordination” has and still is interpreted in two ways. One interpretation is viewed from the technical aspect as “relay coordination” and the second is viewed from an inter-communication aspect as “coordination of information” between entities).

Response: Thank you for your comment.

a. **The drafting team agrees that the use of the term ‘coordination’ in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.**

b. **Based on all the comments received, the drafting team has removed the phrase “…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards”.**

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative, Inc., JRO00088	No	See comments posted by SERC PCS
Response: See response to SERC Protection and Control Subcommittee.		
ACES Power Marketing Standards Collaborators	No	Please strike “while meeting the system performance specified within requirements established in other approved NERC reliability standards.” It provides no additional explanation for the purpose and these “other approved NERC reliability standards” apply regardless of this standard. In generally, it is not necessary to reference other NERC standards within a standard and, in fact, should be avoided as a standard should stand alone.
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase “…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards”.**		
Kansas City Power & Light	No	1. The reliability objective of this standard should be to insure that there is an agreement between two interconnected entities of relay protection schemes and relay protection settings for the interconnected facilities. This is achieved if there is documentation stating that the Interconnected operating companies have reached agreement on protection schemes and protective relay settings. This standard should only require documentation that neighboring owners are talking and agreeing with one another in relation to protection and control. 2. The present purpose makes it appear that you are in violation of the standard any time the system has a misoperation because of relay setting regardless of whether both parties have agreed on the settings used but the measures tend to measure agreement with the other entity. This is the reason that the present purpose needs to be

Organization	Yes or No	Question 1 Comment
		rewritten the auditors may interpret the purpose to indicate any misoperation due to setting issues is a violation.
Response: Thank you for your comment. **1. The drafting team believes the standard does exactly what you stated. The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”. The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.** **2. The drafting team disagrees with the misoperation issue you describe. Misoperations can occur even when Protection Systems are fully coordinated and agreed upon.**		
Southern Company	No	1) Reference the ‘required to isolate Faults ‘. In some cases the design of the protection system may take more Elements out than the faulted element, such as a transformer differential that trips a transmission bus and then opens a HS Bank disconnect. For this reason we would prefer the term ‘as designed’ be used. 2) We feel that it is important to identify the Protection Systems that are to be evaluated; perhaps a clear reference to the NERC Technical reference document?
Response: Thank you for your comment. **1. The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”.** **2. The Protection Systems that must be evaluated are those that are identified in the Applicability section of this standard.**		
Western Area Power Administration	No	Don’t necessarily agree with the statement: “Protection Systems remove from service only those Elements required to isolate Faults..." This statement can be problematic since backup functions such as remote

Organization	Yes or No	Question 1 Comment
		Zone 3 distance elements cannot be overlapped reliably yet are necessary for N-2 and beyond contingencies. Also, in some case it may be desirable to allow for intentional overlap or mis-coordination depending on the circumstances. These issues need to be resolved in the proposed standard or the standard eliminated.
Response: Thank you for your comments. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults".**		
Independent Electricity System Operator	No	We agree with the first part of the purpose statement, but do not find it necessary to include the second part since "meeting the system performance specified within requirements established in other approved NERC Reliability Standards" is universally true for all standards. No one single standard can assure reliability on its own; multiple standards must be complied with to meet one or more reliability objectives and performance targets. We suggest to remove the part "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
American Electric Power	No	AEP recommends the removal of the language, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards". AEP recommends as an alternative to the removal of the language, modification of the language to reference the TOP standards that should be adhered to in conjunction with PRC-027.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
Texas Reliability Entity	No	We support this reliability objective, but feel that it may fall short of fulfilling all of the required Protection System coordination needs, resulting in a gap in the Standards. The major issue that we see in Protection System coordination is with coordination studies conducted WITHIN an individual entity, not between two or more entities. Using the Misoperation data as an indication, for CY2011, out of 202 total Misoperations in the ERCOT region, 46% were due to "Incorrect settings/logic design", however, less than 2% of the Misoperations occurred on Interconnected Facilities between different entities. This suggests the main problem with Protection System coordination is internal to an entity, not between two different entities. This Standard, as well as PRC-001, are somewhat silent as to what internal coordination should be considered "Good Utility Practice", even though there have been instances where internal coordination was not done.
Response: Thank you for your comment. **The previous PRC-001 only applied to coordination between TOPs, GOPs and BAs. The drafting team has chosen not to include internal facilities for two main reasons: the extreme documentation burden that would be involved for minimal benefit as most of this work is done by the same organization, and the drafting team believes that the entities' internal facilities are completely in their control and are the responsibility of the entity. Failure to properly design and implement internal Protection Systems would be an internal lack of procedures and/or a human performance issue which are both outside the scope of this standard. Additionally, PRC-004 requires that entities have corrective actions plans for identified Misoperations which would prevent similar Misoperations.**		
LCRA Transmission Services Corporation	No	Reword the Purpose to state as follows: "To allow for the coordination of Protection Systems at Interconnected Facilities to prevent equipment damage while maintaining proper selectivity during Faults." This phrasing is

Organization	Yes or No	Question 1 Comment
		more consistent with NERC Reliability Standard language where adherence with other reliability standards is not explicitly stated.
Response: Thank you for your comment. **The drafting team believes that restricting the purpose to "preventing equipment damage" does not meet the intended reliability objective.**		
Exelon	No	1. The current Purpose for PRC-027-1 should more clearly and concisely state the purpose of the standard by relating the purpose of the standard to the definition of Protection System Study (the key element of the proposed PRC-027). 2. The statement, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards", is likely to be subject to interpretation by registered entities and auditors alike and cause confusion. The specific Standards should be referenced in a footnote, or the reference should be removed. [For the purposes of this comment and the suggested revision, Exelon removed the reference since we believe this is the best option].Exelon suggests the following revised Purpose "To ensure Protection Systems at Interconnected Facilities operate in the desired sequence to isolate a fault." In our experience, the term "coordinate" (or "coordination") caused confusion in PRC-001-1 and therefore Exelon proposes that the term be omitted. 3. In PRC-001-1, the term "coordination" was unofficially accepted as either the correspondence or communication between entities (i.e., via email, memo, fax, etc.), or as the time response relationship associated with backup protection elements. Thus, to avoid this confusion and to match to the proposed Protection System Study definition, Exelon removed it from our suggested Purpose statement above. If the SDT believes that the term "coordination" should

Organization	Yes or No	Question 1 Comment
		remain, it should be clearly defined. Given the Protection System Study definition, a suggested definition for coordination would be "operation of Protection Systems in the desired sequence to isolate a fault".

Response: Thank you for your comment.

1. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The drafting team believes that the Purpose does not need to address its relation to the Protection System Study in order to accurately reflect the goal of the standard.**
2. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**
3. **The drafting team agrees that the use of the term "coordination" in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.**

Organization	Yes or No	Question 1 Comment
Ameren	No	We recommend that the SDT delete the last part of the purpose "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet 'the system performance specified within requirements established in other approved NERC Reliability Standards' and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003 R1.3.7 already requires the entity to "demonstrate that System performance meets its Table 1 for Category C contingencies" (TPL-001, -002 also have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on all the comments received, the drafting team has removed the phrase “…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards”.</td></tr>
<tr><td>Georgia Transmission Corporation</td><td>No</td><td>The title should state the same as the purpose. Example: "Protection System Coordination of Interconnected Facilities". The purpose is to make each entity communicate protection system and/or facility changes in order to make coordination changes as needed.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”. The drafting team believes the Title and Purpose, as separate components of the standard, are not obligated to be the same.</td></tr>
<tr><td>Dairyland Power Cooperative</td><td>No</td><td>The NERC Protection System definition includes more elements than would need to be coordinated at interconnecting facilities (e.g. batteries, chargers). Please consider revising to include only the protection elements that would need to be coordinated to remove Elements from service to isolate Faults.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”. The drafting team does not see that specific Protection System elements referenced (Batteries and chargers) would be considered in doing a Protection System Study; therefore, your suggested changes have not been made.</td></tr>
<tr><td>NPPD</td><td>No</td><td>Suggestion: Remove “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” since there are other standards that are or will be in place otherwise it sounds like the other standards must have evidence included</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>for this standard documentation as well. Perhaps this standard is not required if the other performance standards are adhered to or have portions of this draft standard included in them.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".</td></tr>
<tr><td>Utility Services</td><td>No</td><td>The purpose should specifically state whether or not this standard applies to BES Elements or all Elements. In consideration of other PRC reliability standards, this standard uses language that implies applicability to all Elements. Under the NERC Standard Development Process, standards are only to be applied to BES equipment, unless the applicability language specifically states a broader application. This standard implies it but does not specifically state it. The standard should be modified to clear up any confusion.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The definition of Interconnect Facilities has been modified as follows: Interconnected Elements: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity". The Applicability section has been modified as follows: Facilities: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements".</td></tr>
<tr><td>Trans Bay Cable</td><td>No</td><td>The language "...remove from service only those Elements required to isolate Faults..." is problematic. Taken literally; only the faulted Element may be isolated, and any adjoining buswork or lines (separate Elements) must remain energized; even the result is no change in the loss of load or capacity. We suggest ""To coordinate existing Protection Systems..." to ensure that this is not interpreted as a construction standard requiring additional Protection Systems.</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults".**		
Oncor Electric Delivery Company LLC	No	Oncor takes the position that the word "only" in the Purpose is too subjective and allows for multiple interpretations. Oncor believes that in order to provide clarity, Oncor suggest that the Purpose be modified as follows:"To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults".**		
TransAlta Centralia Generation LLC	No	The Interconnected Facilities definition is not clear.
Response: Thank you for your comment. **The term "Interconnected Facilities" has been changed to "Interconnected Element" and reads as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity". More details related to why it is not clear are needed prior to addressing your comment.**		
ExxonMobil Research & Engineering	No	
MRO NSRF	Yes	The last part of the purpose, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" is vague and open-ended. The NSRF recommends that the SDT refer to the TPL standards if the intent is to limit responsibility for correct

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>coordination to studied system contingencies</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
Based on all the comments received, the drafting team has removed the phrase “…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards”.</td></tr>
<tr><td>Colorado Springs Utilities</td><td>Yes</td><td>There are cases of weak system interconnected facilities where proper coordination may not be achievable economically, except by severing the interconnect. Allowances should be made for these cases to prevent the severing of weak systems to meet this standard.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
The drafting team does not understand the scenario that is described. If this occurs in circumstances not accounted for in normal Protection System Studies, such as n-2 and above situations, it is not an issue.</td></tr>
<tr><td>Sacramento Municipal Utility District</td><td>Yes</td><td>We agree with the purpose of the standard. We disagree with the execution of this purpose. This standard only addresses a very narrow reliability issue. Does the SDT really believe that this narrow concern needs all the documentation called for in the standard? At a minimum, a Protection System Study, proof that you checked for a +/- 10% Fault current change regularly, and proof that you have communicated with other registered entities on these issues? And this will be for every interconnection. We believes this is regulatory overkill and not indicative of a results based standard.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
The drafting team believes the documentation identified in the requirements is necessary to support the purpose.</td></tr>
<tr><td>Public Utility District No. 1 of Snohomish County</td><td>Yes</td><td>1. We agree with the purpose of the standard. We disagree with the execution of this purpose. This standard only addresses a very</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		narrow reliability issue. Does the SDT really believe that this narrow concern needs all the documentation called for in the standard? At a minimum, a Protection System Study, proof that you checked for a +/- 10% Fault current change regularly, and proof that you have communicated with other registered entities on these issues? And this will be for every interconnection. We believes this is regulatory overkill and not indicative of a results based standard.
Response: Thank you for your comment. **The drafting team believes the documentation identified in the requirements is necessary to support the purpose.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	Yes	Ingleside Cogeneration LP agrees that PRC-027-1 should be tightly focused on Fault isolation only. There are other PRC standards which govern the coordination of UFLS, SPS, phase-distance, and other relay types.
Response: Thank you for your support.		
National Grid USA / Niagara Mohawk	Yes	
Luminant	Yes	
Northeast Power Coordinating Council	Yes	
GP Strategies	Yes	
Progress Energy	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	

Organization	Yes or No	Question 1 Comment
Pacific Gas and Electric Company	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Idaho Power Company	Yes	
City of Austin dba Austin Energy	Yes	
Manitoba Hydro	Yes	
Xcel Energy	Yes	
Tacoma Power	Yes	
Tri-State G & T	Yes	
Public Service Enterprise Group	Yes	
Liberty Electric Power LLC	Yes	
Wisconsin Electric Power Company	Yes	
NV Energy	Yes	
Platte River Power Authority	Yes	
MWDSC	Yes	
Portland General Electric Company	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 1 Comment
mason	Yes	
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
El Paso Electric Company	Yes	
Duke Energy	Yes	
Clark Public Utilities	Yes	
NextEra Energy Inc	Yes	
South Carolina Electric and Gas	Yes	
El Paso Electric	Yes	

2. The SDT assigned the Applicability of PRC-027-1 to Transmission Owners, Generator Owners and Distribution Providers that own the Protection Systems applied at the Interconnected Facilities that require coordination for isolating generation and Transmission Faults. Are you aware of other functional entities that should be included in the Applicability? If so, please provide specific suggestions in the comment area and the reason for including those functional entities.

Summary Consideration:

A large majority of the commenters did not identify any additional entities that should be added to the Applicability.

Various commenters felt that the Transmission Planner, Planning Authority, Transmission Operator and/or Generator Operator should be included. The basis for these requests was the fact that in some cases those entities were identified as providing the Protection System Studies and/or system modeling services for the Owners. An example response to these comments was as follows: The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others.

Several commenters disagreed with the Distribution Provider being included. The drafting team responses indicated that the inclusion of Distribution Providers was appropriate. The drafting team responded that they believe the Distribution Providers that own "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements" should be included in the Applicability of this standard because those Protection Systems must be coordinated with the Protection Systems of other Facility owners.

A few commenters asked for clarification as to whether the standard applied to entities that had multiple registrations (i.e. as a TO and GO). An example response to these questions was as follows: If Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Facilities between Entity A- Transmission Owner and Entity A-Generator Owner. The drafting team will review the language in order to ensure clarity related to this.

The Applicability was slightly modified as a result of these comments and others as follows: 4.2 Facilities: Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.

Organization	Yes or No	Question 2 Comment
FirstEnergy	No	However, it should be clear the DP facilities in scope are only those associated with potentially impacting a BES facility.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. **The drafting team believes Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.** **To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements". Additionally, the drafting team changed the term "Interconnected Facilities" to "Interconnected Element" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".**		
Northeast Power Coordinating Council	No	From a reliability perspective, the Applicability Section of PRC-027-1 should not include the Distribution Provider because the TO is responsible of coordination of the protection with the DP.
Response: Thank you for your comment. **The drafting team believes that the owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if the Transmission Owner is providing such a service it would be by agreement, and does not change the fact the Distribution Provider has the responsibility.**		
MRO NSRF	No	The standard includes the definition of Interconnected Facilities as BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities. It is unclear how the requirements of the standard would apply if a registered entity would fulfill more than one functional entity role. For example if a registered entity was both a Generator Owner and Transmission Owner would the requirements of the standard apply to the interconnection of the generator and transmission facilities? It is recommended that the standard be modified to provide clarity for this situation.
Response: Thank you for your comment.		

Organization	Yes or No	Question 2 Comment
The drafting team's intent is that if Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Facilities between Entity A- Transmission Owner and Entity A- Generator Owner. **Additionally, the drafting team changed the term "Interconnected Facilities" to Interconnected Element" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".**		
PPL Corporation NERC Registered Affiliates	No	Applicability to GOs should be limited as stated above in question #1.
Response: Thank you for your comment. **As noted in the response to #1: The drafting team believes that the Owner of the Protection System is responsible for ensuring its Protection Systems are coordinated with others. It is acknowledged that in many cases, the majority of the work associated with this task will fall on the Transmission Owner; however, the coordination of some Protection Systems owned by Generator Owners installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included.**		
Colorado Springs Utilities	No	The wording of the text suggests that Interconnected Facilities include coordination and documentation of Transmission to Distribution interfaces. Since these are usually contained in different functional or corporate entities it suggests much more documentation, and needs clarified.
Response: Thank you for your comment. **The only Transmission to Distribution interfaces included in this standard are those where the Distribution Providers own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES. Consequently, these facilities are the only ones that would require documentation.**		
Tennessee Valley Authority	No	In some instances end-use customers, such as a large industrial load, take service delivery through an Interconnected Facility. It is not clear that the draft standard covers coordination between a TO and an end-use customer (not registered as a TO, GO or DP) who takes service via a BES Interconnected Facility.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
The drafting team changed the term “Interconnected Facilities” to Interconnected Element” defined as follows: “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity”. The standard only applies to Interconnected Element(s) between registered Transmission Owners, Generator Owners, and Distribution Providers. . To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”.</td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>1. The applicability should also include Transmission Operators and Generator Operators as it is possible for jointly held facilities to be owned by several parties and operated by another party and relay protection responsibilities could be with the Operator of the facility.
2. It should be clarified the proposed Standard is applicable to Distribution Providers that provide protection for BES Elements.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
1. The drafting team believes that the Owner of the facility is responsible for ensuring that its Protection Systems are coordinated with others. It is acknowledged that in some cases the scenario described may exist; however, if the TOP or GOP is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility.
2. To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”. Additionally, the drafting team changed the term “Interconnected Facilities” to “Interconnected Element” defined as follows: “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity”.</td></tr>
<tr><td>LCRA Transmission Services Corporation</td><td>No</td><td>We agree that applicability of the overall standard should be limited to the Transmission Owners, Generator Owners and Distribution Providers; however, requirements for conducting the Protection System Coordination Study should only</td></tr>
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<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>apply to the Transmission Owners, Generator Owners and Distribution Providers that have ownership of the protective relay portion of the Protection System. Requirement R1 should read as follows:”Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System that owns a Protection System shall:”</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that the Applicability section addresses this. Typically the protective relay may be the only component of the Protection System that requires review; however, that is not always the case.</td></tr>
<tr><td>Tri-State G & T</td><td>No</td><td>We agree with this description and the entities, however the standard’s applicability is not written as described in the question. We think that “that require coordination for isolating generation and Transmission Faults” should be added to Section 4.2, Facility Applicability.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on yours and others comments, the drafting team modified the Applicability section 4.2 Facilities as follows: “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”.</td></tr>
<tr><td>Wisconsin Electric Power Company</td><td>No</td><td>The previous version, we think correctly, did not include DP’s in the applicability. Since the revised definition of the BES is currently awaiting FERC approval, the applicability of this standard to the Distribution Provider function is not appropriate. The relevant entities should be limited to TO and GO only.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.</td></tr>
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Organization	Yes or No	Question 2 Comment
Dairyland Power Cooperative	No	It is unclear how the requirements of this standard apply to entities that fulfill multiple functional roles. For example, an entity is registered as both a Generator Owner and Transmission Owner. In the case where a GO and TO are the same entity is it required to show the same type of coordination?
Response: Thank you for your comment. **Yes. The drafting team's intent is that if Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Element(s) between Entity A- Transmission Owner and Entity A- Generator Owner.**		
American Transmission Company	No	ATC is not aware of additional functional entities that should be included.
Response: Thank you for your support.		
NPPD	No	1. This applicability needs clarification. How does this standard relate to the definition of BES? 2. Does including Distribution Providers mean an entity that does not own a transmission protection system is included under this standard? 3. There needs to be clear understanding that radial feeds on load serving transformers such as 115/69kV or 115/34.5kV transformers and low voltage feeders are not included in this standard. 4. Perhaps NERC needs a program to evaluate/identify all functional entities and determine if they should be registered and thus applicable and not have utilities try to determine the status of other utilities or functional entities. 5. Clarify if the Transmission and Generator owner are the same utility how sharing of information is documented or confirm that this relationship means the documentation is not applicable in this standard.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. **1. The drafting team revised the Applicability of this Standard to provide more clarity, it now reads: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements"** **2. No. The drafting team believes Distribution Providers that do not own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES are not included in the Applicability of this standard.** **3. As noted in the revised Applicability section, only Facilities that have "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements" are subject to the requirements of this Standard. In general, radial feeds on load serving transformers such as 115/69kV or 115/34.5kV transformers and low voltage feeders do not have such Protection Systems applied. Please see Figure 4 in the Application Guidelines section of the draft standard PRC-027-1.** **4. This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff.** **5. How to meet the documentation requirements would be up to the entity to determine. The drafting team's intent is that if Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Element(s) between Entity A- Transmission Owner and Entity A- Generator Owner.**		
Utility Services	No	However, using the broad term "Protection Systems", this SDT is broadening the scope of the standard beyond the BES. Due to the recent direction in Project 2007-17 for PRC-005-2, Protection Systems has been expanded to include systems beyond the definition of the BES. This project should limit the applicability for the DP to "transmission Protection Systems" as identified in PRC-004 and 005-1.
Response: Thank you for your comment. **The drafting team revised the Applicability of this Standard to address your and others' comments, it now reads: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements".**		
CenterPoint Energy	No	The proposed term for Interconnected Facilities, shown on page 2 of 27 of PRC-027-1

Organization	Yes or No	Question 2 Comment
		Draft #1, is defined as “BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities.” CenterPoint Energy believes Interconnected Facilities should be defined in reference to NERC registration and recommends changing the definition to “BES Facilities that are electrically joined by one or more Element(s) and are owned by different registered entities.”
Response: Thank you for your comment. **The drafting team considered this option; however, the drafting team felt that ‘registered entities’ would potentially mislead some entities that have different functional registrations, to think that the Standard does not apply to them. The term Interconnected Facilities has been changed to Interconnected Element as follows: “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity”.**		
Dominion	No	
Southwest Power Pool NERC Reliability Standards Development Team	No	
National Grid USA / Niagara Mohawk	No	
Pepco Holdings Inc. & Affiliates	No	
Luminant	No	
Imperial Irrigation District (IID)	No	
Bonneville Power Administration	No	

Organization	Yes or No	Question 2 Comment
Santee Cooper	No	
Detroit Edison	No	
Western Small Entity Comment Group	No	
SERC Protection and Control Subcommittee	No	
Associated Electric Cooperative, Inc., JRO00088	No	
Southern Company	No	
Salt River Project	No	
Operational Compliance	No	
Pacific Gas and Electric Company	No	
Western Area Power Administration	No	
Independent Electricity System Operator	No	
American Electric Power	No	
Sacramento Municipal Utility	No	

Organization	Yes or No	Question 2 Comment
District		
Flathead Electric Cooperative, Inc.	No	
ExxonMobil Research & Engineering	No	
City of Austin dba Austin Energy	No	
Texas Reliability Entity	No	
Manitoba Hydro	No	
Xcel Energy	No	
Tacoma Power	No	
Ameren	No	
Public Utility District No. 1 of Snohomish County	No	
Georgia Transmission Corporation	No	
Platte River Power Authority	No	
MWDSC	No	

Organization	Yes or No	Question 2 Comment
Portland General Electric Company	No	
mason	No	
ATCO Electric	No	
Illinois Municipal Electric Agency	No	
El Paso Electric Company	No	
Trans Bay Cable	No	
Duke Energy	No	
Clark Public Utilities	No	
Oncor Electric Delivery Company LLC	No	
South Carolina Electric and Gas	No	
El Paso Electric	No	
Hydro One	Yes	1. This is related to our comments from Question 1. We believe that the Planning Coordinators (PC) shall be included. PCs are accountable to conduct studies to determine critical clearing times, stable and unstable power swings, etc., to determine coordination. Transmission and Generator Owners do not have access to such information or the

Organization	Yes or No	Question 2 Comment
		tools/experience to conduct such studies. In addition to this there is a possibility that the entity in charge of day-to-day operation of the Interconnection Facilities (likely registered as TOP only) doesn't own the facility and consequently is not registered as a TO. In this case, such facility or the facilities would be out of scope of this standard. We believe that the SDT should refine the Applicability section to encompass the above mentioned cases. 2. From a reliability point of view, we think that this standard should not be applicable to Distribution Providers because the TO is mostly responsible of coordination of the protection with the DP.
Response: Thank you for your comment. **1. The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if PC is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility.** **2. The drafting team believes Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.**		
ISO RTO Council SRC	Yes	Depending on the intent of the requirements as questioned in the comment to question #1, it may be necessary to include planners to provide data for contingent and varying operating conditions to coordinate relays beyond those dedicated to intertie facilities.
Response: Thank you for your comment. **The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, the fact that the planners may be providing some data necessary to complete the evaluation it does not warrant including them in the Applicability.**		

Organization	Yes or No	Question 2 Comment
GP Strategies	Yes	1. We agree that there should be a process for ensuring that the industry continuously evaluates the system and ensures that the relay settings are coordinated and adjusted to meet the dynamically changing grid. However, we disagree that the studies should be conducted by the owners of the facilities. We feel these studied should be conducted by the Transmission Planner or Planning Authority and the cost of the studies should be allocated equally to all users of the grid. Currently, a study is performed when a new facility is added or an existing facility is modified. Typically, the study is conducted by the Transmission Planner as identified in FAC-002 and paid for by the facility that is being modified or is being added. It makes since that these facilities pay for the studies as they are the ones modifying the overall grid and benefit from the modification. In this case the cost should not be barred by an existing facility. 2. The drafting team states that an owner should perform a study when the fault current changes by 10% or greater at their Interconnected Facility. The team may not have taken into account the potential that these changes are not related to that particular facility but rather from a change in the overall dynamics of the grid. For example, an influx of renewable resources (both behind and in front of the meters), retirement of generation, changes to transmission, or changes in load pockets. In addition, it excludes any new facilities added since 2007 from sharing the cost of changes to the grid. The cost for studies conducted for changes to the existing grid should be allocated to all interconnected facilities and should be performed by the Transmission Planner. As defined in the Rules of Procedure, section 500, the Transmission Planner is “the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area.” The Planning Authority is the entity that maintains the information required for the studies and is the entity that could perform the studies at the lowest cost. The cost for performing the studies should be allocated to all entitles doing business on the grid and the cost should be reviewed in a rate case and allocated appropriately.MOD-010 and MOD-012 already provides a requirement

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<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>to provide the characteristics for system studies to the RRO for updating the models that would be used to conduct the studies.
3. These Standards, however, have a gap in that they do not include Distribution Provider as indicated in the proposed PRC-027 Standard. We recommend the drafting team revise MOD-010 and MOD-012 to retrieve all necessary information to update the RRO model and that the Transmission Planner be tasked with performing the necessary studies.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The studies conducted by the Transmission Planner or Planning Authority related to FAC-002 are not necessarily directly related to the protection system study identified by this standard. The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if the Transmission Planner or Planning Authority is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility. It is also noted that Protection System Studies are not generally conducted by the Transmission Planner or Planning Authority.
2. The observation that changes to the grid not directly associated with the Interconnected Element(s) is exactly the driver for the inclusion of a regular review of fault currents at the Interconnected Element(s). If such changes result in a 10% change in the conditions that were used in the last Protection System Study, the need for a new study must be evaluated; however, it does not require a study be done.
3. Modifications of the noted standards are outside the scope of this drafting team.</td></tr>
<tr><td>Idaho Power Company</td><td>Yes</td><td>Yes, Transmission Operators may own protection systems but not the interconnected element due to cost sharing agreements among Entities, for example. The applicability should be expanded to cover the Entity responsible for operation of the protection system element and interconnection.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on the Functional Model, the drafting team does not see how the Transmission Operator would own Protection Systems without also being registered as a Transmission Owner. If such a scenario does exist, it is assumed that it would be by agreement</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
with the Owner, and does not change the fact that the Owner has the responsibility.		
Exelon	Yes	Agree, all entities should be included if they are responsible for engineering of protection systems protecting BES elements at Interconnected Facilities.
Response: Thank you for your comment. **It is unclear to the drafting team which additional entities are being suggested for inclusion.**		
Public Service Enterprise Group	Yes	Within RTOs and ISOs, entities such as PJM and NYISO perform such evaluations as part of their transmission planning process. See PJM Manual 14-B, Appendix G, section G.7 which states: "PJM performs short circuit analysis as part of the annual Regional Transmission Expansion Plan (RTEP) baseline assessment. This analysis includes a study of the entire PJM system based on its current configuration and equipment." Therefore, Transmission Planners should be considered as an applicable entity for R2 as discussed in #9 below
Response: Thank you for your comment. **The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if the RTO or ISO is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	Yes	It would seem like Transmission Planners and Planning Coordinators would have a natural interest in modifications made to relay systems. Their simulations must show that BES performance under various contingencies meets certain criteria. Any information discovered in the course of the Protection System Studies would be of interest to them as well.
Response: Thank you for your comment. **The drafting team agrees; however, the Protection System data that may need to be provided by the owner to the Transmission Planners and Planning Coordinators is covered by other Standards.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td>TransAlta Centralia Generation LLC</td><td>Yes</td><td>The applicability should include other functional entities which should provide power system study data.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
It is unclear to the drafting team which additional entities are being suggested for inclusion.</td></tr>
<tr><td>Liberty Electric Power LLC</td><td>Yes</td><td></td></tr>
<tr><td>NV Energy</td><td>Yes</td><td></td></tr>
<tr><td>ACES Power Marketing Standards Collaborators</td><td>Yes</td><td></td></tr>
</table>

3. **In Requirement R1, the SDT allowed a responsible entity 36 months to have a documented Protection System Study completed for each Interconnected Facility if the responsible entity does not already have a Protection System Study for that Interconnected Facility performed on or subsequent to June 18, 2007 (the effective date of PRC-001-1). Do you agree with this time frame? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Many commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Elements enough time to complete the Protection System Studies, and that there is no evidence there is widespread miscoordination between Interconnected Stations; therefore, the drafting team changed the time frame to forty-eight months.

Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2.

Several commenters stated that the definition of Interconnected Facility is confusing. The drafting team changed the term to Interconnected Element defined as follows: “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity”.

Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”

Organization	Yes or No	Question 3 Comment
Pepco Holdings Inc. & Affiliates	No	1. Each owner should already possess information demonstrating that their protective devices are set to “coordinate” with adjacent protection systems. However, the documentation that presently exists may not be in the form of a formal “coordination study” in a format suitable for audit purposes. Some guidance should be provided indicating what form of documentation is expected,

Organization	Yes or No	Question 3 Comment
		especially by the TO. For instance, on transmission tie lines between different TO's coordination of zone distance elements is fairly straightforward and can be accomplished without a traditional "coordination study". Also settings on pilot schemes need to be exchanged in order to allow for proper operation, but this is also not what is considered a traditional "coordination study". On the other hand, coordination between GO's and TO's is even more complicated. Without some direction as to what specific documentation is required it is difficult to estimate how many existing interconnection points would have to be re-visited in order to produce the required auditable documentation. 2. Some specific examples of what specific type of documentation is required would be helpful. To be safe, most likely all interconnection points would be revisited to ensure adequate compliance documentation. Also, for each revised Protection Study produced (per R1.1) a formal review (R1.2) and approval (R4.1) would be required. 3. As such, with the large number of interconnection points on the system a 60 month time frame would be more appropriate. The SDT acknowledged that they had no evidence that there is widespread miscoordination between Interconnected Facilities when establishing the arbitrary 36 month requirement.

Response: Thank you for your comment.

1. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2.**
2. **Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."**

Organization	Yes or No	Question 3 Comment
3. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists.		
Hydro One	No	1. Hydro One would like to suggest that 60 months would be a more realistic span of time needed in order to formally complete a documented study, or derive a time frame based on the number of interconnections that an entity must conduct studies for. Whether the systems are co-ordinated or not, the work needs to be carried out and documented. In the case of Hydro One there are almost 300 individual generator connections that belong to other entities many of whom do not have onsite protection experts. Most of these connections do not have a formal documented protection co-ordination study. 2. Statements in R1.1.2 and 1.1.3: “unless the entity can demonstrate such a study is not required.” and its corresponding measure: “ or documentation demonstrating why a study is not required for changes described in Parts 1.1.2 and 1.1.3” are vague and don’t give much guidance on what would be the appropriate evidence in this case. 3. Suggest adding examples of documents that can be used to demonstrate compliance.
Response: Thank you for your comment. **1. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Elements. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element**		

Organization	Yes or No	Question 3 Comment
exists" 2. Based on your comment, the drafting team revised Requirement 1, Parts 1.1.2 and 1.1.3 to include the phrase: "or technically justify why such a study is not required". As stated in the Rationale box for Part 1.1.2, one example of a technical justification would be: "when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current". 3. Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."		
Bonneville Power Administration	No	1. This question assumes that the requirement to perform a protection system study is acceptable, and the question focuses only on the timeframe allowed. In BPA's opinion, the requirement to have a protection system study is objectionable and cause for disapproval of the standard. Therefore, the timeframe is irrelevant. 2. In addition, the standard fails to make clear just what a protection system study is, either in the definition, the requirements, or the guidelines that follow. BPA believes that R1 is ambiguous and unacceptable.
Response: Thank you for your comment. 1. The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon. 2. The drafting team made various changes including those to the definition, requirements, and guidelines to clarify what a Protection System Study is. Other commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system		

Organization	Yes or No	Question 3 Comment
Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”		
FirstEnergy	No	Requirement 1, Part 1.1.1 - Although we agree with the timeframe, the phrase “within 36 calendar months after the effective date . . . . subsequent to June 18, 2007” should not be listed as a requirement but rather as part of the Implementation Plan.
Response: Thank you for your comment. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”**		
Detroit Edison	No	Why aren’t studies performed prior to June 18, 2007 considered acceptable if they’re still valid as long as no significant fault current or system changes have occurred?
Response: Thank you for your comment. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2. which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”**		
MRO NSRF	No	1. If an entity has a Protection System Study performed prior to June 18, 2007 that

Organization	Yes or No	Question 3 Comment
		meets the requirements for the study specified in PRC-027-1 and there have been no changes to trigger a new study as specified in PRC-027-1 (that have occurred) the study should be acceptable for compliance with the standard. It is suggested that the requirement R1, sub-requirement R1.1 be revised by removing the phrase "that was performed on or subsequent to June 18, 2007." 2. The NSRF questions if 36 months is ample enough time for large company to get all studies done within 36 months. Unless R1.1 is revised to mean all studies regardless to when it was performed.
Response: Thank you for your comment. 1. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."** 2. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Elements. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**		
PPL Corporation NERC Registered Affiliates	No	As noted in the response to question #1, TOs and DPs have the data and the capability needed to perform the studies that appear to be contemplated by the SDT.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
The drafting team agrees.		
Tennessee Valley Authority	No	1. "Protection System Study" is a new term being introduced with this standard. Since industry documentation of protection system coordination reviews are conceivably available from both before and after June 18, 2007, precluding coordination reviews performed prior to June 18, 2007 from acceptable compliance evidence could greatly increase the workload of protection system engineers during the proposed 36 month time period. Note that there is a possibility of overlap with the "Order 754 request for data" response period. The rationale statement for R1, Part 1.1.1, indicates that the effective date of PRC-001-1 was the basis for selecting June 18, 2007. PRC-001-1 primarily addresses new protective systems and changes (R3 & R5) and coordination with neighboring GOP, TOP and BA entities (R4). We suggest changing the wording of Part 1.1.1 to the following: "Within 36 calendar months after the effective date of this standard, if no valid Protection System Study for that Interconnected Facility exists."
Response: Thank you for your comment. **1. Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).**		
ACES Power Marketing Standards Collaborators	No	(1) Conceptually, we agree with the intent of the standard and this requirement as it is presented in the application guidelines. However, more refinement is needed to make this requirement implement what is explained in the application guidelines. For instance, nowhere in Requirement R1 is it stated clearly that the responsible

Organization	Yes or No	Question 3 Comment
		entity is only responsible for performing Protection System Studies (PSS) for only those breakers it owns and are protecting the Interconnection Facility. This is pretty clear in the application guidelines. (2) While we do not disagree with the time frame, we question if it should be part of the requirement. It makes more sense to include the time frame for initial compliance of a requirement in the implementation plan. In that way, the initial compliance time frame does not persist in the standard long after it is no longer needed. It is common to utilize the implementation plan to describe initial compliance dates. Furthermore, FERC approves implementation plans as part of the standards package so there is no issue with whether the implementation plan is enforceable. (3) We disagree with limiting PSS that can meet this requirement to only those that occurred after June 18, 2007 as defined in Part 1.1.1. While NERC cannot compel evidence from a date before the standards became enforceable, there is no reason that a TO, GO, or DP could not choose to utilize a PSS from before this date as evidence. (4) We think the use of PSS in Part. 1.1 is partly redundant to the definition. The definition indicates PSS is a study that demonstrates Protection Systems operate in desired sequence for clearing Faults. Part 1.1 states that the TO, GO, and DP shall perform the PSS “to verify Protection Systems remove from service only those Elements required to isolate Faults” are removed from service. Isn’t the statement in Part 1.1 “to verify Protection Systems remove from service only those Elements required to isolate Faults” equivalent to the demonstrating that Protection Systems operate in the desired sequence for clearing faults as defined in the PSS? (5) We disagree with including the Distribution Provider in this requirement. The primary reason that a Distribution Provider owns Protection Systems that protect Interconnected Facilities is that it is often cheaper to install a fault interrupting device and its associated Protection Systems on the distribution side. These Protection Systems are typically installed per the Transmission Owner facility connection

Organization	Yes or No	Question 3 Comment
		requirements which are established per FAC-001. The Transmission Owner usually still performs the PSS and short circuit study and the Distribution Provider uses settings specified by the Transmission Owner. The fact that FAC-001 applies only to the TO and allows the TO establish such facility connection requirements that applies to the DP further supports this claim. (6) The definition of Interconnection Facility is confusing and needs further refinement. First, we are not sure what the purpose of including “that are electrically joined by one or more Element(s)” is. If it is not electrically joined, it cannot be a Facility. It would not be part of the BES which is a basic requirement of the Facility definition. Second, it is not clear if this is intended to cover only jointly owned Facilities or not. We do not think that is the intention but the clause “are owned by different functional, operating or corporate entities” cause this confuses. Third, ownership cannot be defined by functional or operating entities. A corporate entity may be registered as a TO and GO. Which part of the definition applies for the interconnection between the transmission system and generator: Functional Entities or Corporate Entities? Furthermore, a functional entity or operating entity does not really describe a legal entity capable of ownership. The definition of Interconnected Facility should be a Facility that ties together two different sets of Facilities together where the Protection System coordination would be performed by different companies. This would appear to be consistent with the explanation of the standards in the application guidelines. For example, a Facility connecting two different TO transmission systems together where the TOs are owned by separate corporate entities would be an Interconnected Facility. A generation interconnection Facility would only be considered an Interconnection Facility if the GO and TO were separate corporate entities. If they were the same corporate entity, coordination would already occur and the generation interconnection Facility should not be considered an Interconnected Facility.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
1. The drafting team believes that the Entity is responsible for conducting the PSS as described in the application guidelines. **2. Making the time frame part of the Requirements was the choice of the drafting team.** **3. Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2.** **4. Several commenters stated that the definition of Interconnected Facility is confusing. The drafting team changed the term to Interconnected Element defined as follows: Interconnected Elements: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".** **5. The Applicability of this standard includes Protection Systems installed for the primary function of detecting Faults on BES Elements irrespective of what functional entity owns them. Protection Systems not installed for the primary function of detecting Faults on BES Elements are not included in the Applicability.** **6. Several commenters stated that the definition of Interconnected Facility is confusing. The drafting team changed the term to Interconnected Elements defined as follows: Interconnected Elements: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".**		
Kansas City Power & Light	No	The protective systems were coordinated when installed. If the power system has not undergone any significant change, then line impedances and fault current levels are the same and the original settings are still valid. So, no new study is required based on the passage of time. A new study is needed only if there have been significant system changes as outlined under question 5 and requirement R3.Requirement 1.1 states each entity must perform a system protection coordination study, however, the coordination efforts will be joint efforts between the entities and sharing of pertinent information such that an effective study can be performed. The proposed Standard should make it clear the study effort can be a joint study between the entities involved and that independent studies are not necessarily intended by each entity.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
The drafting team acknowledges that the identified Protection System Studies can be a joint effort but believes they do not have to be. The drafting team agrees with the concept of joint studies as long as all involved entities have the required documentation.		
Southern Company	No	60 months would be more reasonable for those that have a large number of generators and/or interconnections. Perhaps a tiered approach: 36 months for those with less than 50, 60 months for those with more than 50 but must have 50% done within 36 months?
Response: Thank you for your comment. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists”.**		
Salt River Project	No	The requirement to provide a copy of each Protection System Study is an administrative burden that does not reflect the intent of Results Based Standards. Changing the requirement to maintain evidence that Protection System Studies are coordinated and affected entities have agreed to the results of the Studies is adequate.
Response: Thank you for your comment. **The drafting team is not requiring a Protection System Study; only a summary of the results of the Protection System Study performed is required to be provided to the other entities.**		
Pacific Gas and Electric Company	No	PG&E we believes that the 6 calendar month time frame in requirement R1.1.2 is too short and should be extended to 12 calendar months
Response: Thank you for your comment.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td colspan="3">**The drafting team believes because fault current reviews are conducted every 2 years, the expectation is that the number of instances where the fault current changes by 10 % will be limited. We therefore believe that the 6 month time frame is appropriate and decline to make the suggested change.**</td></tr>
<tr><td>American Electric Power</td><td>No</td><td>1. 36 months is not adequate for unique Protection System Studies to be conducted for the TO, GO, and DP. The interface and coordination requirements as written will require close communication with a vast number of interconnected facilities. In addition the generation landscape changes over the next few years with the large number of generation retirements and additions will continually change the short circuit model. AEP believes that these contributing factors will lead to time requirements above the proposed 36 months currently in the standard. AEP would require a minimum of 60 months to complete this work as the AEP system exists today. An added complication that will impact this time requirement is the approval of FERC Order 1000, which could result in additional interfacing TO's inside AEP's footprint. In addition, NERC's rationale for R1 states that "the SDT has no evidence there is widespread miscoordination between Interconnected Facilities that warrants a shorter time frame." If this is the case, then there should be no issue with extending this timeframe.
2. Using the word "demonstrates" within the definition for Protection System Study could be interpreted as requiring an actual, operational test rather than a simulation study. We recommend changing the definition to "a study that demonstrates that the existing or proposed Protection System design will enables the Protection System to operate in the desired sequence for clearing Faults."
3. Is using the defined term "Protection System" appropriate? Does it possible bring things into scope (CTs, PTs, Station batteries) which should not?</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
1. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists”. **2. The definition of Protection System Study refers to “a study that demonstrates”; consequently, the drafting team believes the word “demonstrates” is appropriate in the context it is used.** **3. As stated, the Protection System does include CTs and VTs which are part of the considerations used when determining the settings of a protective relay. The information needed to be transmitted to another Entity would include this equipment.**		
Sacramento Municipal Utility District	No	There is no need to have a Protection System Study available for review for every Interconnected Facility. The study is useful only as an intermediate product that leads to relay settings and as a basis for both entities to agree that their planned settings will coordinate. The results based objective is that the registered entities communicate and coordinate together. A simple statement by both entities that they have reviewed each other’s settings and agree they coordinate is sufficient proof that the reliability objective of this standard has been met.
Response: Thank you for your comment. **The standard requires a Protection System Study be performed but only requires a summary be provided to the other entity. The standard provides for documentation of the agreement which may be a simple statement as you indicate.**		
Idaho Power Company	No	1. No, Should a Protection System Study under R1 result in triggering of the other Requirements in the Standard, more time may be needed. 2. An Entity could easily find themselves responding to multiple inquiries from Interconnectors while performing their own Studies. Additional time should be allowed to address the results of the Protection System Studies triggered during this implementation timeframe.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. **1. The Requirement R1 time frame only addresses performing a Protection System Study; this time frame is not inclusive of other changes that may result from the Protection System Study and are covered by Requirements R3 and R4.** **2. The time frame for Requirement R1 has been increased to forty-eight months and the drafting team believes this time is sufficient to perform all required studies.**		
Exelon	No	Exelon cannot agree to the time frame proposed without understanding the scope of work involved in the required protection system study. 1. The current definition of Protection System Study (PSS) is not clear enough to avoid confusion. To better define the "study" as referenced in PRC-027-1 and to ensure that applicable entities know what they're required to do, the definition of PSS needs to clarify the elements of the protection system and power system conditions the study is run similar to how required Transmission Planning studies are defined. With this in mind, Exelon suggests the following definition for "Protection System Study": A study that demonstrates that existing or proposed Protection Systems operate in the desired sequence for clearing a fault. The study is conducted with a single power system element out of service and all Protection System elements in service, and with all power system elements in service and a failure of a single protective relay, communication system, ac current input, ac voltage input, or DC control circuit (these can be further defined using the information and Table from Order 754). 2. Exelon suggests that "summary results of a protection system study" should also be defined with clear parameters established. Unless the specific particulars are established, Exelon predicts that there will be confusion as auditors attempt to decide whether or not a piece of evidence will qualify as a "summary" of a Protection System Study. This is similar to the ambiguity in the existing revision of PRC-005-1 R1.2 which requires a "summary" of maintenance and testing procedures, yet does not describe specifically what is required. It is our experience that registered entities and auditors historically have had differences

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>of opinion about what constitutes a “summary”.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. Based on your comments and others, the drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).” Additionally, language has been included in the Guidelines and technical Basis section of the standard to indicate “System conditions used in Protection System Studies include maximum generation and transmission system at normal operating conditions and under single contingency conditions.”
2. Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”</td></tr>
<tr><td>Liberty Electric Power LLC</td><td>No</td><td>I disagree with the requirement for a protection system study. From the draft standard: "The SDT has no evidence there is widespread miscoordination between Interconnected Facilities". There are approximately 18,000 generators in the US. Requiring each to perform a system study would result in costs running into the hundreds of millions of dollars. This will result in lower BES reliability as entities transfer funds from other reliability efforts to comply with this standard.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The drafting team believes the requirements of this standard will enhance the reliability of the BES.</td></tr>
<tr><td>Public Utility District No. 1 of</td><td>No</td><td>Comments: There is no need to have a Protection System Study available for review</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>Snohomish County</td><td></td><td>for every Interconnected Facility. The study is useful only as an intermediate product that leads to relay settings and as a basis for both entities to agree that their planned settings will coordinate. The results based objective is that the registered entities communicate and coordinate together. A simple statement by both entities that they have reviewed each other’s settings and agree they coordinate is sufficient proof that the reliability objective of this standard has been met.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The standard requires a Protection System Study be performed but only requires a summary be provided to the other entity. The standard provides for documentation of the agreement which may be a simple statement as you indicate.</td></tr>
<tr><td>Ingleside Cogeneration LP, (Occidental Chemical Corporation)</td><td>No</td><td>1. This requirement assumes that a material percentage of the many thousands of interconnecting relay systems have a problem. There is no evidence of this; and in fact, the Rationale text box for R1 states that the converse is true. This makes sense, as the inter-operation of Fault isolation Protection Systems is a fundamental and well-understood concept - which may not be the case with the more complex relay types. In our opinion, the two-year TO assessment will be sufficient to catch an issue and drive improvements afterwards. Therefore requirement R1.1.1 should be deleted.
2. In addition, we do not agree with the “on or subsequent to June 18, 2007” time frame, since these studies are completed when a facility is built, and/or when a facility is significantly changed, which could quite possibly be prior to 2007. If studies were completed before June 18, 2007, and nothing significant has changed, the study meets the PRC-027 requirement, and/or the TO assessment does not indicate a need, there is no purpose served by repeating the study.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. For entities that do not have a Protection System Study as specified in Requirement R1 will need to conduct a study to create a baseline for use in the two year TO assessment as outlined in Requirement R2.</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
2. Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2.		
Wisconsin Electric Power Company	No	1. In some cases there may be many Interconnected Facilities between two or more owners. It cannot be expected that owners will be able to support performing multiple studies in parallel, at the same time. It would be best to eliminate the specified timeframe, and allow the owners the latitude to determine the timeframe based on priorities decided by them. 2. Also, replace the phrases in R1.1.2 and in R1.1.3, "... unless the entity can demonstrate such a study is not required", with "unless the entities involved agree that a study is not required". If the interconnected entities agree that a study is not required, there should be no requirement to document the reasons why a study is not required. Likewise, revise M1 to include as acceptable evidence "documentation that the relevant entities have agreed that a study is not required."
Response: Thank you for your comment. **1. The time frame for Requirement R1 has been increased to forty-eight months and the drafting team believes this time is sufficient to perform all required studies.** **2. The drafting team revised Requirement 1, Parts 1.1.2 and 1.1.3 to include the phrase: "or technically justify why such a study is not required". As stated in the Rationale box for Part 1.1.2, one example of a technical justification would be: "when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current". Documentation is needed to verify that an agreement was reached.**		
NV Energy	No	With such a long time frame for conducting this subject study, one cannot assure that the protection systems are coordinated, and there could be an impending mis-coordination that goes uncorrected. Suggest 12 or 24 months.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".		
Dairyland Power Cooperative	No	It is agreed that the there needs to be a time period for Protection System Studies to be performed after the standard takes affect. However, the length of time is a concern due to the industries existing resources. It would be preferred that the time period be lengthened to 60 months.
Response: Thank you for your comment. **Many of the commenters suggested that 36 months was not enough time – suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**		
Platte River Power Authority	No	There is no need to have a Protection System Study available for review of every Interconnected Facility. The results based objective is that the registered entities communicate and coordinate. a simple statement by both entities that they have communicated and coordinated is sufficient.
Response: Thank you for your comment. **The standard requires a Protection System Study be performed but only requires a summary be provided to the other entity. The standard provides for documentation of the agreement which may be a simple statement as you indicate.**		
MWDSC	No	1. Protection Systems installed prior to June 18, 2007 should not be required to redo

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>a study because a system study should have been performed prior to installation based on the interconnected configuration at that time. The interconnected systems will change over time and redoing studies will raise more questions on assigning responsibility for changes beyond the control of the protection system owner.
2. For protection systems installed prior to June 2007, TOs should only be required to show a study was performed and coordinated with appropriate interconnected entities.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
1. Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."
2. A valid Protection System Study will require the same documentation, regardless of the date of completion.</td></tr>
<tr><td>American Transmission Company</td><td>No</td><td>1. ATC does not agree with the time frame proposed.
2. The existing requirements in PRC-001 do not require protection system studies with Distribution Providers. As such, even though studies have been completed there may be no package (documentation) to support an audit. This requirement assumes that, if there is no existing fault study, one needs to be completed. If there have been no changes in short circuit or protective schemes, allow for completion of the studies based upon prioritization using voltage class and loading level.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td colspan="3">1. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists”
2. The drafting team modified Requirement R1, Part 1.1.1 to make studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”</td></tr>
<tr><td>NPPD</td><td>No</td><td>To mitigate compliance risks for various types of data formats for existing studies and studies older than June 2007 this standard will likely require utilities to go back and update all data so that it meets the requirements and description of evidence in the application guidelines when the requirements become enforceable. This could likely take longer than 3 years. I would recommend more time such as 6-10 years (time depends on the number of applicable system ties as well)</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists”.</td></tr>
<tr><td>CenterPoint Energy</td><td>No</td><td>(a) The proposed term for Protection System Study, shown on page 2 of 27 of PRC-027-1 Draft #1, is defined as “A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.” CenterPoint</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>Energy recommends Protection System Study instead be defined as “A study that demonstrates Protection Systems operate as desired for clearing postulated short circuit Fault events.”
(b) CenterPoint Energy believes a 36 month implementation to have a documented Protection System Study completed for each Interconnected Facility is overly burdensome, unless certain Interconnected Facilities are exempted. CenterPoint Energy recommends exempting Interconnected Facilities that are serving only load and that are connected by no more than two transmission line Elements that are operating between 100 kV to 200 kV. Many of these Interconnected Facilities have fault-proven, time-proven protection system set points. Additionally, Draft #1, on page 5 of 27, notes that protection system misoperations related to coordination issues are addressed by PRC-004.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
a. The definition of Protection System Study refers to “a study that demonstrates”; consequently, the drafting team believes the word ‘demonstrates’ is appropriate in the context it is used.
b. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists”.</td></tr>
<tr><td>NextEra Energy Inc</td><td>No</td><td>While 36 months is allowed for studying all interconnections, what time is allowed for mitigation of identified setting or hardware change?   If an issue is discovered, then an additional 12-24 months mitigation time should be allowed.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The Requirement R1 time frame only addresses performing a Protection System Study; this time frame is not inclusive of other</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
changes that may result from the Protection System Study and are covered by Requirements R3 and R4.		
Oncor Electric Delivery Company LLC	No	Given the “agreement” requirements defined in Requirement R4 and the uncertainty of its interpretation, many of the recent protection system studies may have to be performed again. Therefore, a more appropriate timeframe would be 5 years to have all applicable Protection System Studies completed.
Response: Thank you for your comment. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists”.**		
Western Area Power Administration	No	
ExxonMobil Research & Engineering	No	
National Grid USA / Niagara Mohawk	Yes	As a TO our experience has been that many GOs do not reply to requests for information. If the 36 month window cannot be met by a TO because information requests are ignored what recourse does the TO have to avoid a penalty for non-compliance?
Response: Thank you for your comment. **Requirement R3, Part 3.2 specifies that the “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.” In your example, the GO would be in violation of this standard.**		

Organization	Yes or No	Question 3 Comment
Associated Electric Cooperative, Inc., JRO00088	Yes	AECI objects with the line of questioning here, because it does not fully address all aspects of Requirement R1. While AECI appreciates the 36 month time-frame, we did receive internal comment back from our planning engineers Relay Operations Sub-Committee: 1) Concerning our Regional Entity's Short Circuit Data Working Group, the current status is such that a unilateral AECI SC study would be technically difficult. 2) Further, significant modeling development will be necessary in order for entities to comply with this requirement through a regional study formation, i.e. 3 yrs is a definite push on the timeline on the Initial pass. 3) Finally, the information to be reported from a Protection System Study R1.1, and particularly the information to be communicated to other entities R1.2, may be too vague. This primary concern is for personnel being inundated by the sheer volume of data that can now be performed in relation to such studies. AECI would appreciate the SDT providing further Industry Guidance as to what would constitute a clear and concise set of information, to be transmitted or received from corresponding parties.

Response: Thank you for your comment.

1. **The drafting team believes that a short-circuit study is required to meet the requirements of this standard and acknowledges that this is a collaborative effort.**
2. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**
3. **Requirement R1.2 has been modified to include additional details for the summary of results as follows: "or technically justify why such a study is not required".**

Organization	Yes or No	Question 3 Comment
Flathead Electric Cooperative, Inc.	Yes	This seems like an adequate time, but it is unclear that smaller transmission dependent utilities really need to do this to maintain reliability and if their ratepayers would see any reliability benefit.
Response: Thank you for your comment. **This standard is applicable to Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.**		
LCRA Transmission Services Corporation	Yes	Requirement R1 should read as follows:"Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System shall: "Requirement R1.1.2 should read as follows: Within 6 calendar months after determining or being notified of a change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.
Response: Thank you for your comment. **1. In the case where different portions of the Protection System are owned by different entities, then the Protection System Study must be a collaborative effort.** **2. The drafting team revised Requirement 1, Part 1.1.2 to include the phrase: "or technically justify why such a study is not required".**		
Xcel Energy	Yes	The standard does not specify M2 violation reporting responsibility or assignment of violation due to non-responsiveness of the interconnected entity. Clarification needs to be made as to what is considered acceptable evidence that the affected entity received the study results under measure M2. Would a registered mail confirming receipt at an address be considered acceptable evidence; if not what type of document service would be considered acceptable?

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. **Registered mail confirming receipt at an address would be considered acceptable evidence. Additional acceptable evidence would be letters, or emails acknowledging receipt.**		
Public Service Enterprise Group	Yes	We do not believe this requirement has been justified for the several reasons listed below. In addition, the "Protection System Study" definition is too vague as to what it should include. We suggest a separate appendix that lists the items that this study should address. We also suggest that the SDT develop several baseline and change case Protection System Study examples, using a common format. These should be incorporated into an appendix within the standard. a. The format and overall purpose of the baseline study has not been provided. It is highly unlikely that a sufficient Protection System Study has been completed or is available for a majority of the Interconnected Facilities since 6/18/2007 within North America. This is due in part to either no modifications being performed at these facilities or lack of data retention (a study was performed but since it was not a requirement, documentation is not available). To require entities to now perform such studies would be a sizeable undertaking and create a tremendous burden to all entities with little benefit to the entities and the reliability of the BES. For older Interconnected Facilities where no changes have been made in several decades, no benefit to the facility or the BES would come from perform such a study. b. The only time a Protection System Study should be performed is when a driver is in place that will require a possible relay setting changes. These drivers should be spelled out specifically. For example, if there is substation project work that requires relay setting changes, if the relays are being replaced, if a "tie line" is being re-conductored, etc. The requirement to perform a study should also apply to those "interface" relaying schemes that would normally require periodic review. The requirement for a periodic review will be driven by something other than a system configuration change. This may include schemes that have current operated relaying

Organization	Yes or No	Question 3 Comment
		where the setting of the relay is dependent of fault current level. c. The complexity of such a study is uncertain. In most cases, the “interface” relaying between two TO’s or a TO and a GO is very straightforward. In the case of the “interface” between a TO and a GO, the relaying may simply be a transformer differential scheme. In the case of a tie line between two TOs, if the relaying is strictly impedance based, then there is no need to perform a baseline study. In other cases, the study may be more complex. The study may also have to incorporate Protection System devices beyond the Interconnected Facility (e.g. BOP protection for generators, adjacent line or bus protection for transmission facilities). This would increase the amount of time and complexity required to perform the study. How would the SDT define the appropriate protection coordination boundaries for an Interconnected Facility?
Response: Thank you for your comment. **a. Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).” Entities that do not have a Protection System Study as specified in Requirement R1 will need to conduct a study to verify Protection System coordination and to create a baseline for use in the two year TO assessment as outlined in Requirement R2.** **b. Requirements R2 and R3 provide the triggering points that indicate when a new study is necessary.** **c. The drafting team acknowledges that the complexity of the Protection Systems applied will determine the scope of a Protection System Study and in some cases may not be required; however, this does not preclude the need for a baseline study. Application Guidelines provide examples of the protection boundaries.**		
mason	Yes	Although the timeframe appears reasonable, the more basic question about the necessity of the documentation requirements needs to be reconsidered.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon.		
Duke Energy	Yes	However R1 is confusing by having two sub-requirements R1.1 and R1.2, two measures M1 and M2, and VSLs consisting of various combinations of non-compliance with sub-requirements. We think it could be made clearer by separating R1.2 out as a separate requirement with its own measure and VSLs. We have made a similar comment on Question 8 that other requirements, measures and VSLs in this standard could be made clearer by breaking them apart. Also, Requirement R1.2 states “each affected Interconnected Facility owner” without describing how the owner may be affected.
Response: Thank you for your comment. **The drafting team used the format recommended by NERC staff.**		
Dominion	Yes	
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
Luminant	Yes	
Imperial Irrigation District (IID)	Yes	
Santee Cooper	Yes	
Western Small Entity Comment Group	Yes	

Organization	Yes or No	Question 3 Comment
SERC Protection and Control Subcommittee	Yes	
Colorado Springs Utilities	Yes	
ISO RTO Council SRC	Yes	
Progress Energy	Yes	
Operational Compliance	Yes	
Independent Electricity System Operator	Yes	
City of Austin dba Austin Energy	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Tri-State G & T	Yes	
Ameren	Yes	
Georgia Transmission Corporation	Yes	
Portland General Electric	Yes	

Organization	Yes or No	Question 3 Comment
Company		
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
El Paso Electric Company	Yes	
Trans Bay Cable	Yes	
Clark Public Utilities	Yes	
South Carolina Electric and Gas	Yes	
El Paso Electric	Yes	

4. In Requirement R2, the SDT established a +/- 10 % change in an Interconnected Facility's Fault current value as a criterion for notifying interconnected entities to give the interconnected entity a "heads up" that a review of the existing documented Protection System Study may be warranted. Do you agree with the +/- 10 % Fault current threshold for initiating this review? If not, please provide an alternative means along with a technical justification for determining a threshold.

Summary Consideration:

A majority of the commenters agreed with the 10% deviation trigger. Of those that disagreed and provided an option, they suggested a range of 15-20%. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows timely notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.

Multiple commenters expressed confusion as to where the fault needed to be applied, what branch(s) needed to be monitored, and what system conditions needed to be considered. Some expressed that the fault should be applied at the bus so that batch studies could be run to automate the short circuit study. The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."

Based on comments, the drafting team reworded Requirement R2 to provide clarity. The requirement now reads: "For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall:"

Several commenters suggested modifying the equation to replace "V" with "I". The drafting team made the change.

Organization	Yes or No	Question 4 Comment
Pepco Holdings Inc. & Affiliates	No	The 10% threshold would be acceptable providing the following changes were made to Requirements R2.1 and R2.2:R2.1 – 1. Re-word Requirement R2.1 to read: "Perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities, not less than once every 24 months. 2. R2.2 - Re-word Requirement R2.2 to read: "Calculate the percent deviation

Organization	Yes or No	Question 4 Comment
		between the maximum available Fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation...” The existing wording requires one to “calculate the percent deviation between the fault current values ... for the bus(s) or Elements(s) under consideration”. 3. Including the phrase “or Element(s) under consideration” increases the complexity of the periodic fault screening requirement significantly. Instead of performing a relatively easy bus fault summary routine (available in most batch short circuit programs) individual branch current in various coordination pairs must be examined. Take for example the system shown in Figure 1 in the Application Guidelines. Instead of just screening the available bus fault current at the point of interconnection (the ownership boundary between the two entities), fault current in each “element under consideration” used in the Protection study must be calculated. This would mean determining fault current flows through breakers A, B, C, D, E, F, G, & H) under various fault scenarios and comparing them to those used in the previous coordination study. This is far from a simple task and not conducive to a “batch” screening tool. The intended purpose of R2.2 is to catch external system changes that have over time led to gradual increases in fault current that may require the Protection System Study to be re-examined. A simple year to year bus fault comparison would serve this purpose. System changes at, or immediately adjacent to, the interconnection point, which could lead to a re-distribution of fault currents through the effected element(s), would be caught elsewhere under R3.1 “Additions, removals, or replacements of transmission Elements”.

Response: Thank you for your comments.

1. **Per your suggestions and others, the drafting team has modified Requirement 2.1 to read “Perform a short-circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus,**

Organization	Yes or No	Question 4 Comment
not less than once every 24 months.” **2. The drafting team believes the existing wording was sufficient and did not make your suggested change.** **3. The drafting team did remove the word “or Element(s)” as you suggested.**		
Hydro One	No	Hydro One agrees with the need of a defined fault current threshold. However, we’d like to suggest a 20% threshold instead as most protection settings, if coordinated properly, must coordinate with system normal and under credible minimum system conditions, therefore, it is our opinion that a 10 % change should generally not affect coordination.
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.**		
Bonneville Power Administration	No	This question assumes that the requirement to perform a mandatory short-circuit study every 24 months is acceptable, and the question focuses only on the percent change of the study results that will require notification. BPA believes that a short-circuit study should not be required and the percent change that triggers notification is irrelevant.
Response: Thank you for your comment. **The drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.**		
Detroit Edison	No	Recommend that the “trigger” be a system change (line, transformer, generator) that

Organization	Yes or No	Question 4 Comment
		results in an impedance change.
Response: Thank you for your comment. **Requirement R3 of this standard allows for system changes to trigger a study as you suggest. However, the drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination.**		
Northeast Power Coordinating Council	No	1. Agreed that a change in fault current is a method to trigger a coordination study, but a 15% threshold would be more efficient (+/- 15 %). 2. Clarify where the fault is to be applied and where the deviation is to be observed. One possibility is to apply the fault at a bus at one end of the tie and then determine the deviation in the current in each element connected to that bus.
Response: Thank you for your comments. **1. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.** **2. Per your suggestions and others, the drafting team has modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
PPL Corporation NERC Registered Affiliates	No	See comment in question #1 above.
Response: Thank you for your comment. **Please see the SDT's response to your comments in question #1.**		
Colorado Springs Utilities	No	In order to avoid burdensome paperwork of traditional fault study values and existing

Organization	Yes or No	Question 4 Comment
		fault study values, common thresholds should be determined for initiating a review. Common thresholds can be common device ratings, or agreed upon levels at interconnects. As in Facility ratings, each owner should have device ratings for device capacities and can include short circuit ratings, which if exceeded can initiate a review.
Response: Thank you for your comment. **The drafting team agrees with your comment about establishing a common threshold but it is related to Protection System coordination rather than device ratings. The threshold we arrived at is a 10 % deviation of the Fault current values used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1.**		
Tennessee Valley Authority	No	1. The 10% change is too narrow for protection system studies. Accuracies of PT, CT, wiring, and modeling all add together and therefore the threshold for a new protection system study should be 15%.a) 2. In R2, Part 2.2, replace the term “deviation” with “change.” (Note: For this calculation all that’s required is to calculate percent change. i.e. Webster’s dictionary definition of “deviation” is 1) A variation that deviates from the standard or norm; "the deviation from the mean”. 2. The difference between an observed value and the expected value of a variable or function.) 3. In R2, Part 2.2, replace the term “present” with “new” and the term “most recent” with “previous”. Also reflect this terminology change in the % Change equation.(the use of the terms “present” and “most recent” can be perceived to be the same.) 4. It is also recommended that “V” for value be replaced by “I” for current. d) In R2, Part 2.1, please add “new”, delete “present” and add either “under normal conditions” or “maximum system conditions” so that it states “Perform a new short circuit study to determine the fault current values under normal conditions, not less than once every 24 months."

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. **1. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.** **2. The drafting team believes that the term “deviation” is properly used in R2 Part 2.2 and is synonymous with the term “change”.** **3. The drafting team believes that the terms “present” and “new” are properly used in R2 Part 2.2 and are synonymous with your recommended changes.** **4. Per your suggestions and others, the drafting team has modified the equation to replace “V” with “I”. The drafting team modified Requirement 2.1 to read “Perform a short-circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus, not less than once every 24 months.”**		
ACES Power Marketing Standards Collaborators	No	(1) While we do not have an issue with the +/- 10% Fault current threshold, we question if the TO should be responsible for calculating the percent deviation for all Protection Systems for all Interconnected Facilities. Rather the TO should be responsible for calculating Fault currents on its transmission system and should be required to calculate the percent deviation for only those breakers and associated Protection Systems it owns and are protecting an Interconnected Facility and that it has performed the Protection System Study (PSS). The TO should communicate the Fault current to the owners of other Protection Systems protecting the Interconnected Facilities for them to calculate the percent deviation. (2) The main part of the requirement needs to be modified to further clarify for which Interconnected Facilities the TO is conducting short studies. As it is written now, each TO has to perform these short circuit studies for each Interconnected Facility. This literally means a TO has to perform short circuit studies for Interconnected Facilities for which it has no information or is even remotely responsible. For example, a literal reading would mean a TO in the Eastern Interconnection would have to perform a short circuit study for an Interconnected

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>Facility in the Western Interconnection. Obviously, this is not the drafting team’s intention but the language does need refinement.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The drafting team changed the text in Requirement R2 to read: “For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall”.
2. The drafting team changed the text in Requirement R2 to read: “For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall”.</td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>a. Primary protection of most transmission lines is impedance based. Sensitive ground over current systems are used for communications assisted tripping and time ground over current systems are typically used as backup protection. Some line protection is differential based. Some entities also apply instantaneous ground over current relaying for faults at some fraction of the protected line. Increases in fault current do not affect impedance based relaying. Communications assisted sensitive ground elements are set well below available fault current levels and increases in fault current levels will not hinder proper operation. Differential based systems would also not be harmed by fault current increases unless fault currents increase enough to result in ct saturation. Since time ground over current relays are usually used as backup protection they are typically set only to operate if the primary relaying protection has failed. These relays are typically set to coordinate based on time delays for ground faults on the protected line. Because the overcurrent curves are based on a log scale the increase in current magnitude does not correlate to the same percentage in time. Instantaneous ground over current elements are most susceptible to misoperations caused by increases in fault current, however these elements should be initially set to protect only the first 50 to 70% of the protected line based on the fault current at the remote end. With this in mind a fault current increase of 10% is not significant by itself to require</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>a setting review and it is very difficult to see how a 10% decrease can affect the coordination unless over current elements are the primary protection elements or over currents elements can prevent the operation of the other protection functions. If the SDT is adamant about having a periodic review of fault current levels then the time should be extended to 5 years
b. and the fault current level should be increased to 20% on the protected line.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
a. Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation. The drafting team believes studies associated with changes that would affect the coordination in less time would be triggered by other requirements in this standard.
b. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.</td></tr>
<tr><td>Operational Compliance</td><td>No</td><td>1. We agree with the 10% value, but not with the actual wording in the Standard. The Standard reads "2.3 Where the calculation performed....indicates a deviation in Fault current of 10% or greater". It is not clear whether this means 10% Fault current deviation above or below, both or just above.
2. We also suggest that specific defined trigger events prompt a Fault current review for affected Interconnection Facilities, instead of fault current reviews being required every 24 months for every Interconnection Facility.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The drafting team changed the formula to take the absolute value of the calculated percent deviation to make it clear that the</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">percent change is plus or minus 10 %.
2. Requirement 3 provides the specific defined trigger events as you suggest, however, the drafting team believes that a periodic Fault current study is still necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination.</td></tr>
<tr><td>Pacific Gas and Electric Company</td><td>No</td><td>The requirement to run the fault study to determine if there is any 10% change is only required once every 24 months per requirement R2.1. But if you run a batch study and find a bunch of 10% changes, you only have 6 months to do all the coordination studies. We think a 12 month window for performing the coordination studies is more appropriate.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that complying with Requirement R3 will minimize the situation you describe.</td></tr>
<tr><td>Western Area Power Administration</td><td>No</td><td>We have concerns over what NERC considers to be a "Protection System Study". Needs to be defined more clearly.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team modified the description of the term “Protection System Study” in the Technical Guidelines section of the standard.</td></tr>
<tr><td>Independent Electricity System Operator</td><td>No</td><td>We do not agree or disagree with the 10% deviation threshold. In the Technical Justification document, the SDT indicates that “The SDT investigated various inputs that would trigger a review of the existing Protection System Studies, and determined through the experience of the SDT 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 Protection System Study may be necessary.” Lacking statistical or detailed studied results, this basis is as good as any. However, there does not appear to be any assessment made on the potential</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		BES reliability risks when the Fault current deviates by less than 10%. Many Protection Systems' settings are linked to Fault current level and as such, deviation as low as a few percent may render a Protection relay not operating as intended. We suggest the STD to assess the risk of not conducting a verification study for the Protection Systems when Fault current deviates from past values at a lower range to either confirm that a 10% deviation would be a safe trigger, or revise it according to the findings of the risk assessment. (NTD: we may also suggest that a Protection System Study should be required for every BES modification that is in the electrical proximity of the Interconnected Facility and is expected to modify the Fault current levels.)
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10 %. The drafting team did not make any of the suggested changes. Further, Requirement 3 should capture Fault current changes caused by BES additions.**		
Sacramento Municipal Utility District	No	1. We do not agree with this requirement. The selection of a +/- 10% threshold is entirely arbitrary. For instance, some entities will set Z1 to 80%, leaving a 20% margin for error. Some entities will set it at 90%. The SDT should allow entities to decide for themselves when a review is needed. 2. As we stated before, the results based objective is to communicate and coordinate. Not to prove whether the fault current at a certain bus is +/- XX% greater than it was at some time in the past. Furthermore, the SDT itself states there is no proof that failure to coordinate protection systems is causing reliability issues. If entities allow their systems to become uncoordinated, we would expect it to come to light as a Misoperation and be handled under PRC-004. We do not agree it is the TO's responsibility to maintain a short circuit model for other entities. What responsibility does the TO take on if it models a generator's short

Organization	Yes or No	Question 4 Comment
		circuit capability incorrectly? This is a very real concern among transmission protection engineers when attempting to model large wind farms with their proprietary models.
Response: Thank you for your comments. 1. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10%.** 2. **The expectation is that the Transmission Owner will be reviewing short circuit values on the Transmission Owner's facilities only. When the Transmission Owner identifies a 10% deviation at a location where there are Interconnected Elements, the Transmission Owner would notify the other entity(s). The Transmission Owner is identified as the entity responsible for performing the Fault current studies because they maintain the data necessary to perform the studies.**		
ReliabilityFirst	No	It may be appropriate to trigger a coordination review based on multiple criteria. For instance, perhaps coordination should be verified at the interconnection at least once every 7 years, as well as whenever the available fault current at the point of interconnection changes by more than 10%. There may be other better indicators when coordination should be checked as well such as a percentage change in system impedances at the interconnecting buses. RFC also questions whether there is a justification for choosing the 10% criteria (rather than say 5%)
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Further, Requirement 3 should capture Fault current changes caused by BES additions; therefore, the drafting team believes a periodic study as you suggest is not warranted.**		
Idaho Power Company	No	No, We are unsure whether a 10% trigger level is appropriate in this context as the location of the fault is not specified in this Requirement. Faults used to properly set a

Organization	Yes or No	Question 4 Comment
		protective relay will be made at multiple locations and with various source conditions. The Requirement should be more specific in order to achieve consistent coordination among entities.
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The 10% trigger will potentially initiate a Protection System Study which could involve evaluating Faults at multiple locations and with various source conditions.**		
LCRA Transmission Services Corporation	No	1. A 10% change in fault current is not an appropriate criterion or "trigger" for relay coordination review. It does not meet the standard's purpose to ensure speed and selectivity requirements associated with protection system coordination. Requirement R2 should read as follows: "For each Interconnected Facility, each Transmission Owner that has ownership of the protective relay portion of the Protection System shall: " 2. Requirement R2.2:LCRA TSC recommends not including this requirement. Requirement R2.3: Should the SDT decide to include requirement R2.2, then rephrase R2.3 as follows:"Where the calculation performed, pursuant to Requirement R2, Part 2.2, indicates a deviation in Fault current of 10% or greater, notify each non-transmission owner of the Interconnected Facility, at which the 10% or greater deviation applies, within 30 calendar days after identification. As an alternative requirement to R2.2 and R2.3, LCRA TSC recommends the following language to R2.1, 2.2 and 2.3:2.1. Perform a short circuit study to determine the present Fault current values, not less than annually. 2.2. Pursuant to Requirement R2, Part 2.1, provide summary results to each directly impacted non-Transmission Owner entity at the Interconnected Facility, within 30 calendar days after completion of the short circuit study. 2.3 Delete

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.
2. The drafting team believes the requirement is appropriate as written.</td></tr>
<tr><td>Exelon</td><td>No</td><td>1. Exelon requests that the conditions under which the required short circuit (SC) study are to be performed should be defined. What future reinforcements should be assumed in the SC model, since the result will depend on these assumptions?
2. In R2, 10% or greater deviation in Fault Current may not be adequate to perform Short Circuit (SC) Study. It should be clearly stated what threshold is adequate to perform SC study successfully, and
3. the SDT should provide some examples how the ‘six-month” time frame is considered a “reasonable amount “of time to perform the SC study.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The drafting team revised Requirement R2, Part 2.1 to indicate that the maximum available Fault current values are to be calculated. It is intended that current system models are to be used when performing the 24 month calculations, not future models.
2. The drafting team maintains that the 10% threshold is adequately sensitive and should be conducted every twenty-four months.
3. The drafting team believes that 6 months is adequate time to perform a Protection System Study triggered by a 10% deviation in current magnitudes at an interconnection. These Protection Systems should have been previously checked and documented under a Protection System Study and any settings changes should be minor.</td></tr>
<tr><td>Massachusetts Municipal Wholesale Electric Company</td><td>No</td><td>MMWEC endorses the comments submitted by NPCC.</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **See the response provided to NPCC's comments.**		
Public Service Enterprise Group	No	We disagree with this requirement for several reasons. a. A change in short circuit Fault current, in many cases, does not require relays to be reset. The requirement to perform a Protection System Study for this reason alone will likely provide no benefit when the relay performance is not dependent on short circuit current level. If the relay performance is directly dependent on short circuit level, then a % change in short circuit level may be appropriate. This distinction should be spelled out in R2. b. It is common for relays to be set at 30-50% of the Fault current or 150%-200% of the full load current. A change of +/- 10% in Fault current would have little to no impact on the existing settings and coordination.
Response: Thank you for your comments. **a. Requirement R1, Part 1.1.2 allows you to offer a justification as to why a Protection System Study is not needed even if Fault duty increases by 10%.** **b. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.**		
Public Utility District No. 1 of Snohomish County	No	Comments: 1) SNPD does not agree with this requirement. The selection of a +/- 10% threshold is entirely arbitrary. For instance, some entities will set Z1 to 80%, leaving a 20% margin for error. Some entities will set it at 90%. The SDT should allow entities to decide for themselves when a review is needed. 2) As we stated before, the results based objective is to communicate and

Organization	Yes or No	Question 4 Comment
		coordinate. Not to prove whether the fault current at a certain bus is +/- XX% greater than it was at some time in the past. Furthermore, the SDT itself states there is no proof that failure to coordinate protection systems is causing reliability issues. If entities allow their systems to become uncoordinated, we would expect it to come to light as a Misoperation and be handled under PRC-004. We do not agree it is the TO's responsibility to maintain a short circuit model for other entities. What responsibility does the TO take on if it models a generator's short circuit capability incorrectly? This is a very real concern among transmission protection engineers when attempting to model large wind farms with their proprietary models.
Response: Thank you for your comments. **1. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10%.** **2. The expectation is that the Transmission Owner will be reviewing short circuit values on the Transmission Owner's facilities only. When the Transmission Owner identifies a 10% deviation at a location where there are Interconnected Elements, the Transmission Owner would notify the other entity(s). The Transmission Owner is identified as the entity responsible for performing the Fault current studies because they maintain the data necessary to perform the studies.**		
Georgia Transmission Corporation	No	1) Using "V" to denote fault current values may help the non-engineer reading the document, but "I" is the common nomenclature for current in the utility industry. The equation in R2.2 should use "I" in place of "V". 2) There is a risk in using calculated fault currents of the most recent PSS and not existing relay settings. If the entity uses 10% margin in settings it will be too late to make settings changes. Should the margin be based on existing fault calculations and existing relay settings basis?
Response: Thank you for your comments.		

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<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">1. The drafting team made the suggested change replacing “V” with “I” in the equation.
2. The drafting team does not understand the scenario you describe.</td></tr>
<tr><td>Platte River Power Authority</td><td>No</td><td>The selection of a +/- 10% change in an Interconnected Facilty's Fault current value is arbitrary. The results based objective is to communicate and coordinate.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.</td></tr>
<tr><td>MWDSC</td><td>No</td><td>1. Every TO should not be required to perform a short-circuit study every 24 months if there were no significant changes to that TO's BES facilities. Changes in adjoining interconnected BES systems could change short-circuit duties for an adjoining TO's system. The TO whose BES changes should be responsible for performing short-circuit duties on all adjoining systems as part of Requirement R3.
2. In addition, FAC-002-1 requires TOs to coordinate with TPs and PAs in the assessments of proposed new facilities, including evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission through steady-state, short-circuit, and dynamics studies.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes. Further, Requirement 3 should capture Fault current changes caused by BES additions.
2. The statements you make about FAC-002-1 are correct, however, Requirement R1.4 of that standard requires the</td></tr>
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Organization	Yes or No	Question 4 Comment
Transmission Owner to evaluate system performance under short circuit and other conditions in accordance with the TPL-001-0, TPL-002-0 and TPL-003-0 planning standards. The "coordination" reference in FAC-002-1 is synonymous with "cooperation". No reference to Short Circuit Studies for the purpose of verifying protective relay coordination is made in FAC-002-1. The drafting team believes that Short Circuit Studies as proposed in PRC-027 adequately accomplish the purpose of the standard.		
NPPD	No	Monitoring for a 10% change in faults could trigger studies that are not needed and it is not necessarily a good indicator settings updates are needed. It would be more practical to require a review of settings on a set interval (5 years) or as required by R3.
Response: Thank you for your comments. **The drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.**		
NextEra Energy Inc	No	It would seem that NERC Standards efforts, such as PRC-027 should focus on areas that have a record of poor performance and a contributor to misoperations. The area of tie line protection addressed in PRC-027 is not an area of poor performance, see page 4 of the attachment "....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". Areas that are less problematic should be addressed by NERC with less intrusive methods such as Industry Alerts, general cautionary statements or a standard with less detailed documentation requirements. Thus, PRC-027, as drafted, will unnecessarily require additional focus and resources be placed in an area that has not been a problem for the reliability of the BES. Alternatively, PRC-027 should be drafted much less prescriptively from a technical standpoint, and allow for more discretion on how to conduct the study and how to coordinate the results. The prescriptive nature of many of the technical

Organization	Yes or No	Question 4 Comment
		requirements PRC-027 is so narrow that it may counterproductive. A results-based approach here should focus more on conduct a study and coordinating the results, rather than dictating how the technical requirements of how study is to be completed.
Response: Thank you for your comments. **PRC-027-1 is replacing Requirements R2 and R3 of PRC-001-2. The drafting team is developing a standard based on a SAR accepted by the Standards Committee and is addressing directives issued by FERC in Order 693.**		
ExxonMobil Research & Engineering	No	
Liberty Electric Power LLC	No	
National Grid USA / Niagara Mohawk	Yes	Please clarify where the fault is to be placed and where the deviation is to be observed. One possibility is to place the fault at a bus at one end of the tie and then determine the deviation in the current in each element connected to said bus.
Response: Thank you for your comment. **Per your suggestions and others, the drafting team has modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
SERC Protection and Control Subcommittee	Yes	a) In R2 2.2, replace the term "deviation" with "change." (Note: For this calculation, all that is required is to calculate percent change. For example, Webster's dictionary definition of "deviation" is: 1) a variation that deviates from the standard or norm; "the deviation from the mean" 2) the difference between an observed value and the expected value of a variable or function.) b) In R2 2.2, replace the term "present" with "new" and the term "most recent" with

Organization	Yes or No	Question 4 Comment
		"previous". Also reflect this terminology change in the %Change equation. (The use of the terms "present" and "most recent" can be perceived to be the same.) c) It is also recommended that "V" for value be replaced by "I" for current. d) In R2 2.1, please add "new", delete "present" and add either "under normal conditions" or "maximum system conditions" so that it states "Perform a new short circuit study to determine the Fault current values under normal conditions, not less than once every 24 months.
Response: Thank you for your comments. **a. The drafting team believes that the term "deviation" is properly used in R2 Part 2.2 and is synonymous with the term "change".** **b. The drafting team believes that the terms "present" and "new" are properly used in R2 Part 2.2 and are synonymous with your recommended changes.** **c. Per your suggestion, the drafting team has modified the equation to replace "V" with "I".** **d. The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
Associated Electric Cooperative, Inc., JRO00088	Yes	1. A 10% threshold seems simple, but the SDT may or may not wish to clarify the formula to be applied because any of the following is a valid interpretation: 1) abs(Vscs - Vpss)/Vscs, 2) abs(Vscs - Vpss)/Vpss, 3) abs(Vscs - Vpss)/0.5(Vscs + Vpss), 4) abs(Vscs -Vpss)/Max(Vscs,Vpss), or 5) abs(Vscs-Vpss)/Min(Vscs,Vpss). 2. Also see SERC PCS Comments.
Response: Thank you for your comments. **1. Initially, the posted standard was missing the equation but the document was reposted with the equation included. The drafting team modified the equation to include the absolute value.**		

Organization	Yes or No	Question 4 Comment
2. Please see the drafting team's responses to the SERC PCS comments.		
Southern Company	Yes	When calculating the "+/- 10 % Fault current threshold", the use of bus fault values vs the line contribution values should be clarified.
Response: Thank you for your comment. **The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
Texas Reliability Entity	Yes	1. Using a +/- 10% change is a good threshold, with the understanding that if a change in fault current value of less than 10% results in a need to change relay settings, then Requirement R3.1 will cover the coordination between entities in that case. 2. Additional comment: For R2.1, Does the SDT also want to consider other system studies in addition to short circuit studies (e.g. critical clearing time studies at generation facilities needed for breaker failure coordination, equipment rating studies, or stability studies)?
Response: Thank you for your comments. **1. Your understanding about R3.1 covering the scenario you describe is correct.** **2. The drafting team doesn't believe that the other studies you mention should be considered in this standard.**		
Xcel Energy	Yes	Similar comments on measure M5 as contained in item 3 above on measure M2.This provision should become effective 36 months after the effective date of the standard.
Response: Thank you for your comments. **The drafting team believes that the description of the evidence in the Measure is acceptable. The drafting team further believes**		

Organization	Yes or No	Question 4 Comment
that the 24 month time frame to perform a short circuit study is adequate.		
Ameren	Yes	(1) In R2 2.1 we request the SDT add “under normal conditions” or “under maximum system conditions” so that it states “Perform a short circuit study to determine the present Fault current values under normal conditions, not less than once every 24 months. “ (2) We request the SDT clarify which Interconnection Facility fault current values are to be compared. If the intent is to keep this general so the entities have the flexibility to compare those fault current values that the entities judge appropriate, please state. Otherwise we suggest adding “Specifically find fault current values flowing into each terminal of the Interconnected Facility for independently applied single line to ground and 3-phase short circuits at its other terminal(s).” (3) We request the SDT change R2 2.2 wording to “Calculate the percent [delete - deviation] change between the Fault current values (single line to ground and 3-phase [delete - for the bus(s) or Element(s)] flowing into each terminal of the Interconnected Facility under consideration) used in the most recent Protection System Study...”. This along with our recommended change to R2 2.1 clarifies the short circuit values that are to be compared. (4) We request the SDT change R2 2.1 to “not less than once every 5 years” for consistency with TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. Our experience is that PRC-027-1 R3 will trigger almost all Protection System Studies anyhow.
Response: Thank you for your comments. **1. The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.”** **2. The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">where a Protection System Study is available per Requirement R1.”
3. The drafting team believes that the term “deviation” is properly used in R2 2.2 and is synonymous with the term “change”. We also believe that the changes made to R2.1 clarify where the fault is to be applied and monitored.
4. The reliability intent and purpose of the two standards is different. The drafting team agrees with you that Requirement R3 should capture Fault current changes caused by other BES additions.</td></tr>
<tr><td>Ingleside Cogeneration LP, (Occidental Chemical Corporation)</td><td>Yes</td><td>Ingleside Cogeneration LP agrees that a 10% delta in Fault current is material and would warrant further study. However, we are not sure how these studies would correlate to those managed by Planning Coordinators and Transmission Planners. It seems like these entities would have to be involved in any studies that may result in a change in relay settings or a Protection System upgrade.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team does not believe the Planning Coordinators or Transmission Planners need to be involved in Protection System Studies associated with verifying protective relay coordination.</td></tr>
<tr><td>American Transmission Company</td><td>Yes</td><td>ATC does agree with the premise of the a 10% change but believes that the SDT needs to provide a clear definition of which fault current must change 10% to trigger the notification requirements and initiation of a protection study. Fault current on an interconnecting line may change very little even though bus fault contributions from other lines may have increased considerably, affecting in feed current and relay settings.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.”</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	However it's unclear what Fault duty is being referred to. Is it the total Fault current at the bus, or Fault current that flows down the line or to the generator? It should also be clarified that Fault duty is the normal case (i.e. with all sources and all lines in-service).
Response: Thank you for your comment. **The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
Oncor Electric Delivery Company LLC	Yes	Oncor takes the position that the 10% fault current threshold criteria is the only criteria needed;
Response: Thank you for your comment.		
Dominion	Yes	a) In R2-2.2 Replace the term "deviation" with "change". {(Note: For this calculation all that is required is to calculate percent change. i.e. Webster's dictionary definition of "deviation" is 1) A variation that deviates from the standard or norm; "the deviation from the mean". 2. The difference between an observed value and the expected value of a variable or function. This is not a statistical calculation.) } b) In R2-2.2, Replace the term "present" with "new" and the term "most recent" with "previous". c) Change the % Deviation Equation to % Change. Reflect as stated above in the equation legend (the use of the terms "present" and "most recent" can be perceived to be the same). d) Replace "V" (Value) with "I" (Current) in the % Change Equation. "V" is frequently used to represent Voltage and this could lead to confusion. e) In M5 Replace the term "deviation" with "change".

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>f) In R2-2.1 please add “new”, delete “present” and add either “under normal conditions” or “maximum system conditions” so that it states “Perform a new short circuit study to determine the Fault current values under normal conditions, not less than once every 24 months.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comments.**
a. The drafting team believes that the term “deviation” is properly used in R2 Part 2.2 and is synonymous with the term “change”.
b. The drafting team believes that the terms “present” and “new” are properly used in R2 Part 2.2 and are synonymous with your recommended changes.
c. See response to “a”.
d. Per your suggestions and others, the drafting team has modified the equation to replace “V” with “I”.
e. See response to “a”.
f. The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.”</td></tr>
<tr><td>Southwest Power Pool NERC Reliability Standards Development Team</td><td>Yes</td><td></td></tr>
<tr><td>Luminant</td><td>Yes</td><td></td></tr>
<tr><td>Imperial Irrigation District (IID)</td><td>Yes</td><td></td></tr>
<tr><td>FirstEnergy</td><td>Yes</td><td></td></tr>
<tr><td>Santee Cooper</td><td>Yes</td><td></td></tr>
</table>

Organization	Yes or No	Question 4 Comment
Western Small Entity Comment Group	Yes	
ISO RTO Council SRC	Yes	
Progress Energy	Yes	
Salt River Project	Yes	
American Electric Power	Yes	
Flathead Electric Cooperative, Inc.	Yes	
City of Austin dba Austin Energy	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Tri-State G & T	Yes	
Wisconsin Electric Power Company	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
Portland General Electric	Yes	

Organization	Yes or No	Question 4 Comment
Company		
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
Trans Bay Cable	Yes	
CenterPoint Energy	Yes	
Clark Public Utilities	Yes	
South Carolina Electric and Gas	Yes	
MRO NSRF		1. The NSRF recommends that a clear definition of what fault current must change 10 % to trigger the notification requirements and initiation of a protection study. Fault current on an interconnecting line may change very little even though bus fault contributions from other lines may have increased considerably, affecting in-feed current and relay settings. 2. It would be easier to implement a time-based periodic review of settings every 5 - 8 years (or sooner if required by conditions in Requirement R3). 3. R2 is redundant and could subject entities to double jeopardy in conjunction with the new TPL standards which will require annual short circuit studies and NERC studies should not be duplicated to avoid double jeopardy. 4. At a minimum, the 24 month requirement should be changed to at least every 2 calendar years. This would align with the annual requirement for the TPL standards. The new TPL standards are in limbo with FERC's rejection to footnote b.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.”
2. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10%. The drafting team did not make any of the suggested changes. Further, Requirement 3 should capture Fault current changes caused by BES additions.
3. The requirements in the two standards are different and therefore not redundant.
4. The drafting team disagrees and believes that the 24 month frequency is adequate.</td></tr>
<tr><td>El Paso Electric Company</td><td></td><td>It is unclear whether the proposed standard intends to reach 10% or greater deviations that accumulate over the course of a more extended period of time (i.e., greater than 2 years), or whether an entity can seek to perform multiple studies within a compressed period of time in such a way that it can ensure that a 10% deviation will not be reached from study to study, as illustrated below:
o Study performed in Year 1 shows a 5% deviation
o Study performed 12 months later (in Year 2) shows a 5% deviation
o Study performed 12 months later (in Year 3) shows a 5% deviation[Cumulative deviation of 15% within 3 years, but only a 5% deviation from study to study]</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The intent is to capture cumulative changes over time and perform a new Protection System Study when the 10% threshold is reached. The starting point is the most recent Protection System Study in which the relay settings were established or verified. At least every two years after that, a new Short Circuit Study is performed and the new short circuit values are compared to the short circuit values from the original Protection System Study. In your example, a new Protection System Study would be triggered after</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
the Short Circuit Study in year 2 when the cumulative 10% deviation occurred.		
El Paso Electric		It is unclear whether the proposed standard intends to reach 10% or greater deviations that accumulate over the course of a more extended period of time (i.e., greater than 2 years), or whether an entity can seek to perform multiple studies within a compressed period of time in such a way that it can ensure that a 10% deviation will not be reached from study to study, as illustrated below: o Study performed in Year 1 shows a 5% deviation o Study performed 12 months later (in Year 2) shows a 5% deviation o Study performed 12 months later (in Year 3) shows a 5% deviation[Cumulative deviation of 15% within 3 years, but only a 5% deviation from study to study]
Response: Thank you for your comment. **The intent is to capture cumulative changes over time and perform a new Protection System Study when the 10% threshold is reached. The starting point is the most recent Protection System Study in which the relay settings were established or verified. At least every two years after that, a new Short Circuit Study is performed and the new short circuit values are compared to the short circuit values from the original Protection System Study. In your example, a new Protection System Study would be triggered after the Short Circuit Study in year 2 when the cumulative 10% deviation occurred.**		
mason		No comment

5. **In Requirement R3, the SDT included a list of proposed changes that impact the coordination of Protection Systems and would initiate a need to inform other entities. Do you agree that this is an appropriate and inclusive list? If not, please provide specific suggestions for additions or deletions with your reasoning(s) in the comment area.**

Summary Consideration:

Several commenters suggested minor wording changes to the list included in Requirement R3, Part 3.1. The drafting team considered all of the suggestions and made changes including combining the second and third bullets to read as follows 'Changes to a transmission system Element that change any sequence or mutual coupling impedance'. Also, the fourth and fifth bullets were modified to indicate that impedance changes are what need to be communicated.

A few commenters had concerns with the 30 day time frame in Parts 3.2 and 3.3 while other commenters wanted them eliminated. The drafting team explained that they believed the 30-day time frame is appropriate and declined to make the change, and further explained the purposes for the Parts and retained them with minor wording changes.

Some commenters wanted to remove reference to schedules in the requirements. The drafting team reinforced that they believe the sharing of project schedules is a necessary communication between entities.

Some commenters did not like the use of the word "error" in Requirement 3, it was restated as follows: 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.

A few commenters expressed concerns that there is redundancy between this draft standard and several FAC standards. The drafting team stated their belief that these concerns were not applicable.

Organization	Yes or No	Question 5 Comment
Southwest Power Pool NERC Reliability Standards Development Team	No	In R3 we would suggest that re-rating could be use as a temporary procedure which is addressed in the TOP standards and if the drafting team needs to include these types of re-ratings that they be more specific to exclude the temporary re-ratings. Changes to generator unit(s), including replacements, Output change that causes a change in the protection system, and impedances

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment **The drafting team believes that if a temporary or permanent re-rating modifies the conditions used in the coordination of Protection Systems of the Interconnected Stations, then any associated protective relay setting changes must be provided to the other entities.**		
Pepco Holdings Inc. & Affiliates	No	The 10% threshold would be acceptable providing the following changes were made to Requirements R2.1 and R2.2:R2.1 – 1. Re-word Requirement R2.1 to read: "Perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities, not less than once every 24 months. 2. R2.2 - Re-word Requirement R2.2 to read: "Calculate the percent deviation between the maximum available Fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation..."The existing wording requires one to "calculate the percent deviation between the fault current values ... for the bus(s) or Elements(s) under consideration". 3. Including the phrase "or Element(s) under consideration" increases the complexity of the periodic fault screening requirement significantly. Instead of performing a relatively easy bus fault summary routine (available in most batch short circuit programs) individual branch current in various coordination pairs must be examined. Take for example the system shown in Figure 1 in the Application Guidelines. Instead of just screening the available bus fault current at the point of interconnection (the ownership boundary between the two entities), fault current in each "element under consideration" used in the Protection study must be calculated. This would mean determining fault current flows through breakers A, B, C, D, E, F, G, & H) under various fault scenarios and

Organization	Yes or No	Question 5 Comment
		comparing them to those used in the previous coordination study. This is far from a simple task and not conducive to a "batch" screening tool. The intended purpose of R2.2 is to catch external system changes that have over time led to gradual increases in fault current that may require the Protection System Study to be re-examined. A simple year to year bus fault comparison would serve this purpose. System changes at, or immediately adjacent to, the interconnection point, which could lead to a re-distribution of fault currents through the effected element(s), would be caught elsewhere under R3.1 "Additions, removals, or replacements of transmission Elements".
Response: Thank you for your comments. 1. **Per your suggestions and others, the drafting team has modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."** 2. **The drafting team believes the existing wording was sufficient and did not make your suggested change.** 3. **The drafting team did remove the word "or Element(s)" as you suggested.**		
Hydro One	No	While we agree with the principle of exchanging information, R3.1 is confusing "...or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities." We believe that this statement is too inclusive. It implies that changes in facilities other than the Interconnected Facility need to be communicated and is too open for interpretation. Suggest the scope be better defined and limited only to changes at the Interconnected Facility.
Response: Thank you for your comment **The drafting team revised the term "Interconnected Facilities" to "Interconnected Element". The drafting team believes changes at other Facilities that modify the conditions used in the coordination of Protection Systems of the Interconnected Elements need to be communicated because they could lead to coordination issues. An example of this is a new substation installed near**		

Organization	Yes or No	Question 5 Comment
Interconnected Elements that could require a change in impedance relay settings for overreaching zones.		
Luminant	No	Luminant agrees with R3.1 and 3.2. Luminant suggests that the language in this requirement be revised so it is clear what is to be provided between the parties.
Response: Thank you for your comment. **Requirement R3, Parts 3.1, 3.2, and 3.3 each refer back to the main Requirement R3. The drafting team revised Requirement R3, Part 3.2 to clarify that it pertains to responses for Protection System coordination information.**		
Bonneville Power Administration	No	BPA believes that it is not practical to list all of the possible changes that could impact the coordination of protection systems. Any such list will likely lead to unnecessary notification in most cases, while failing to recognize unusual situations that could cause miscoordination. BPA is in favor of a simplified approach where notification is provided to the owner of the remote terminal(s) whenever a change is made to the protection scheme at one terminal.
Response: Thank you for your comment. **The drafting team appreciates your concern but believes changes to a protection scheme are not the only system changes than can lead to miscoordination.**		
FirstEnergy	No	Requirement 3, Part 3.1 - We believe that some entities registered as both a TO and a GO may face Standards of Conduct issues if a TO is required to provided the “bulleted” data specified within the Part 3.1.
Response: Thank you for your comment. **The drafting team does not believe that the requested exchange of information would violate the Standards of Conduct for an entity registered as both a GO and a TO.**		
Santee Cooper	No	In R3, 3.3.1, change the wording to address “changes” instead of “corrections” for “errors.” Many changes are made that are not the result of errors. The purpose here

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>should be to communicate changes, and people shouldn’t have to debate whether or not to make an “improvement” (not because of an error or misoperation) because it may be construed as a correction of an error.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: “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.”</td></tr>
<tr><td>Western Small Entity Comment Group</td><td>No</td><td>R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Requirement R2 requires the Transmission Owners to perform the Fault current studies because they have the necessary information to perform the studies. Requirement R1 requires all applicable entities to perform Protection System Studies. Requirement R3 requires all applicable entities to exchange the information necessary for Protection System coordination.</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>No</td><td>DP must be excluded from R3. See the response to Question 2.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
The drafting team believes that the Owner of the Protection System is responsible for sharing information to ensure its Protection Systems are coordinated with others.</td></tr>
<tr><td>PPL Corporation NERC Registered Affiliates</td><td>No</td><td>See comment in question #1 above.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">**The drafting team revised the term “Interconnected Facilities” to “Interconnected Element”. The drafting team believes that coordination is required at all Interconnected Elements between Transmission Owners and Generator Owners regardless of whether the entity is an independent Generator Owner. It is acknowledged that in many cases, the majority of the work associated with this task will fall on the Transmission Owner; however, the coordination of some Protection Systems applied on generators must be verified by the Generator Owner.**</td></tr>
<tr><td>SERC Protection and Control Subcommittee</td><td>No</td><td>a) Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout this standard already address notification requirements.
b) In R3 3.3.1, change requirement to read: “Changes are made to a Protection System as a result of findings during misoperation investigations, commissioning, or maintenance activities.”(The current wording implies that all findings are due to errors. The reference to errors should be removed and the emphasis of this requirement needs to be placed on “changes” made to Protection Systems when it becomes apparent that a change is required which impacts coordination of relays.)</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
a. The drafting team believes it is necessary to share the pertinent scheduling information that could affect the other party.
b. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: “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.”</td></tr>
<tr><td>Colorado Springs Utilities</td><td>No</td><td>Specific project schedules can potentially cause violation of other requirements.
1. A proposed change of conductor spacing, which can be interpreted as a change of one transmission structure requires notification to other entities, which we feel is excessive.
2. Re-rating of generators rarely changes the protection, impedances or coordination involved. It is common to re-rate units depending on external factors to the</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		generator which also provides excessive reviews and project schedule notifications. 3. This section also implies notifications must be made after like and kind replacements of equipment found during misoperation investigations, but not those found during testing. On larger systems this requirement would be difficult unless notifications were made more than twice a month, which would require a large tracking system of who, what, and when information is sent to interconnected utilities.
Response: Thank you for your comment **1. The drafting team has modified the bullet in 3.1 to read ”Changes to a transmission system Element that changes any sequence or mutual coupling impedance’; therefore, the noted change in spacing that does not change the impendence used in the system model would not need to be communicated.** **2. The drafting team believes that, regardless of the probability of a change affecting Protection Systems; it must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.** **3. The drafting team believes that testing is included in commissioning and maintenance activities. The drafting team believes that relay replacement information needs to be provided to the interconnecting entity and that 30 calendar days is sufficient and adequate to provide the notice.**		
Tennessee Valley Authority	No	a) Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout this standard already address notification requirements. b) In R3,Part 3.3.1, change Requirement to read: “Changes are made to a Protection System as a result of findings during Misoperation investigations, commissioning, or maintenance activities.” (The current wording implies that all findings are due to errors. The reference to errors should be removed and the emphasis of this Requirement needs to be placed on “changes” made to Protection Systems when it becomes apparent that a change is required which impacts coordination of relays.)

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<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.
a. The drafting team believes it is necessary to share the pertinent scheduling information that could affect the other party.
b. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: “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.”</td></tr>
<tr><td>Associated Electric Cooperative, Inc., JRO00088</td><td>No</td><td>1. AECI believes the industry would be better served by placing this list of items into a Guidance document, and rephrasing R3 to include only “field-changes known to modify the conditions used in coordination settings of Protection Systems.” Although some of the listed items are direct-impact, as currently drafted, any field-equipment changes are potentially in scope, regardless of proximity to the Interconnected Facility(s) of interest.
2. With exception of R3.1 Bullet #1, the R2.3 10% is a better metric and the other Guidance bullets and wording we proposed above, should be added into R2.3.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
1. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.
2. The drafting team respectfully disagrees and declines to make your suggested changes.</td></tr>
<tr><td>ACES Power Marketing Standards Collaborators</td><td>No</td><td>In general, we are supportive of the list and requirement because it helps to clarify what changes are intended in Part 1.1.3 in Requirement R1. However, we have identified two specific issues with the list.
(1) First, we question if this requirement is at least partly duplicative with FAC-001-0 R2.1.2 which requires the TO to have procedures for notification of new or modified equipment.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		(2) Second, the third bullet regarding additions, removals, and replacements of transmission system Elements is too broad. This literally means that if a TO replaces a bus section with similar equipment, this requirement to notify of changes is triggered which then triggers a Protection System Study or documentation that one is not required per Requirement R1 Part 1.1.3. Ultimately, we believe the changes that need to be identified are those that actually affect the Protection Systems for the Interconnected Facilities or those that change the Fault current on the Interconnected Facilities. (3) The 30 day requirement should be struck from Part 3.2. If a schedule is not identified by any party, it must not be pressing and an artificial deadline should not be created. (4) The language of the main requirement needs to be further refined. A literal reading would require the TO, GO, and DP to provide details about Interconnected Facilities that they neither own nor operate or to which they are even connected. Obviously, the literal meaning is not intended. The requirement needs to be refined to clarify that the TO, GO, and DP only need to provide the details for Facilities they own. (5) For Part 3.3.2, we suggest clarifying that this requirement does not apply if the equipment is replaced with like equipment and settings. (6) We also suggest that that some sort of exemption is written into this part for extreme weather events that allows more time for notifications.

Response: Thank you for your comment

1. **While FAC-001 Part R2.1.2 does require the Transmission Owner to have a procedure, the drafting team believes the two requirements are not duplicative. PRC-027-1 Requirement R3 requires the communication of Protection System information between owners of Interconnected Elements.**
2. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be**

Organization	Yes or No	Question 5 Comment
communicated. **3. The drafting team believes that 30 days is a sufficient time to reply to a request for information; however, the requirement provides flexibility to negotiate an extended schedule.** **4. The drafting team revised Requirement R3 for clarification, indicating that the owner shall provide details to only Responsible Entities connected to the same Interconnected Element.** **5. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: “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.”** **6. The drafting team believes that 30 calendar days is sufficient and adequate to provide the notice and declines to make a change.**		
Kansas City Power & Light	No	Bullet item #3 is too broad. The NERC Glossary definition for Element 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.”. For example, a disconnect switch would be considered an Element, but a change of this component would not warrant a change to relay protection. Recommend modifying bullet item #3 to, “Additions, removals, or replacements of transmission system Element(s) that have an impact on relay protection systems or component(s)”
Response: Thank you for your comment. **Based on your and other comments, the drafting team revised Requirement R3 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.**		
Southern Company	No	Reference the bullet on Line items; the issue of mutual coupling and/or overhead grd wire replacement or changes should be included. Perhaps change to any change that impacts the positive, or zero sequence impedance.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **Based on your and other comments, the drafting team revised Requirement R3 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.**		
Western Area Power Administration	No	1. What are the details to be provided? 2. Should only be for significant changes.
Response: Thank you for your comment **1. The drafting team believes that the examples of the provided information are clear but leave flexibility between the two parties.** **2. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.**		
Flathead Electric Cooperative, Inc.	No	Comments: R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward
Response: Thank you for your comment **Requirement R2 requires the Transmission Owners to perform the Fault current studies because they have the necessary information to perform the studies. Requirement R1 requires all applicable entities to perform Protection System Studies. Requirement R3 requires all applicable entities to exchange the information necessary for Protection System coordination.**		
Manitoba Hydro	No	(1) It is not clear what this list should include. Should the protection changes on the interconnected facilities only be included? Or should it include the protection

Organization	Yes or No	Question 5 Comment
		changes on the adjacent elements? (2) Also, for the changes of power system elements, should those connected directly to the interconnecting bus be included or it should also include changes beyond that?
Response: Thank you for your comment **1. The drafting team believes Protection System changes at other Facilities that modify the conditions used in the coordination of Protection Systems of the Interconnected Elements need to be communicated because they could lead to coordination issues.** **2. The drafting team believes changes at other Facilities that modify the conditions used in the coordination of Protection Systems of the Interconnected Elements need to be communicated because they could lead to coordination issues. An example of this is a new substation installed near Interconnected Elements that could require a change in impedance relay settings for overreaching zones.**		
LCRA Transmission Services Corporation	No	(1) Requirement R3 should read: Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System shall provide to each directly impacted Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility, the details (e.g., project schedule, protective relaying scheme types and settings) as follows: (2) The first bullet of requirement R3.1 should read: New installation, replacement with different types, or modification of: protective relays or protective function settings that result in a direct impact on protection system coordination to an entity at that Interconnected Facility. (3) The second bullet of requirement R3.1 should read: Changes to positive or zero sequence line impedance by more than 5 percent
Response: Thank you for your comment **1. The drafting team believes that the Applicability section appropriately describes which entities and for which installations**		

Organization	Yes or No	Question 5 Comment
require exchange of data. **2. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available. (3) Based on your comment and others, the second bullet of Requirement R3, Part 3.1 was modified (and combined with the third bullet). However, the drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.**		
Exelon	No	In the current draft of PRC-027-1, Requirement 3.1 mandates that for any of the listed network changes, entities must communicate "the details", (i.e., design information to all entities that share the interconnection). Of the network changes/additions listed in the draft, however, some may result in little or no changes to existing protection system coordination settings, thereby having no impact to Protection Systems of other entities. For example, consider a project by a TO to replace a BES circuit breaker at an Interconnected Facility. Assume that breaker failure protection for that circuit breaker will also be upgraded, but that the settings and all protection functions for the new relay remains unchanged from the old system. According to the language of Requirement 3.1, the TO would be required to transmit design information to other entities associated with the interconnected facility even though the project would have no impact to the other entities. This represents one example of a frequently performed project in which design information is not presently shared between entities at an Interconnected Facility. Mandatory compliance with this requirement, as written, could represent a significant burden to the industry by requiring unnecessary communication of design details to other entities, in addition to the added compliance documentation activity, and having no impact to protection systems of the recipients. Exelon suggests that the SDT clarify Requirement 3.1 such that that if a change to an Interconnected

Organization	Yes or No	Question 5 Comment
		Facility is not expected to result in a change to the desired sequence of Protection System operations , the compliance activities required by R3.1 should be waived
Response: Thank you for your comment. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.** **In your specific example, the drafting team believes that, if the proposed breaker failure protection change does not modify the impedances used in the calculation of fault currents, then the information does not need to be exchanged.**		
Tacoma Power	No	1. This list does not appear to sufficiently address BES transformers (e.g., autotransformers). 2. There is concern that R3.1 may introduce either an administrative burden to identify and track every change, including those that would not reasonably impact Protection System coordination, or compliance jeopardy if those changes are not identified and tracked. a. For example, the second bullet under R3.1 refers to changes to line spacing. Assume that, during restoration following a Fault, a damaged insulator on one pole or tower is replaced with an insulator one inch longer. Technically, this changes the line spacing. It is doubtful that the SDT intended that this or a similar but less trivial scenario would trigger a Protection System Study; however, the language may introduce compliance jeopardy. Perhaps a similar metric as used in R2.3 could be applied to the second, third, fourth, and fifth bullets. For example, perhaps a 5% change in interconnecting Element impedance from a baseline could trigger a Protection System Study; this approach could be used in lieu of the second and fifth bullets. It seems that R2.3 would address the third and fourth bullets if the short circuit study were conducted before the change was implemented. b. Additionally, the language in the first bullet under R3.1 may introduce compliance jeopardy. For instance, it is possible for an entity to adjust a current and/or voltage

Organization	Yes or No	Question 5 Comment
		transformer ratio and compensate with one or more relay settings such that the primary settings do not change. In many of these cases, there will be no impact on Protection System coordination. While active communication among entities is advised, the potential for fines in this type of scenario does not seem to be appropriate. The emphasis on the first bullet under R3.1 should be on Protection System scheme (e.g., distance, overcurrent, DCB, POTT, differential), primary settings (including time delays), independence/redundancy, and technology (primarily for communications systems).
Response: Thank you for your comment **1. The drafting team believes that BES transformers are addressed in the original third bullet, which is now combined into the second bullet, of Requirement R3, Part 3.1.** **2a. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** **In your specific example, the drafting team believes that the type of damage replacement that you suggested is so small that it would not modify the impedances used in the calculation of fault currents and would therefore not need to be communicated to the interconnecting entity. Part 3.1 does not trigger a Protection System Study.** **2b. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the type of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.**		
Public Service Enterprise Group	No	a. R3 should be rewritten as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider shall provide the following to each Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility:" b. Part 3.1 should be modified as follows: "For any change or additions listed below,

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>provide a project schedule and the reason for the project, whether to an existing or new Interconnected Facility or to other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities:”
c. Part 3.2 does not read well and is not supported by the explanation in the text box. It references 1.1.1, 1.1.2, and 1.1.3, but none of these parts allow an Interconnection Facility owner to request information from another owner to perform the Protection System Study. We can understand why Interconnection Facility owners need to cooperate in the performance of such studies. This thought belongs in R1. We suggest a new 1.2 (with the existing 1.2 renumbered to 1.3) as follows: “Each Interconnected Facility owner shall provide data requested by another owner and which is needed to perform the study in 1.1, either in accordance with an agreed-upon schedule, or within 90 days of receiving the request.” We believe 30 days is too short to require a response.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
a. Requirement R3 was reworded to enhance clarity.
b. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.
c. The drafting team believes that nothing in the requirements precludes an entity from asking for necessary data, and requirements are needed to ensure that requested data is provided. The drafting team believes that 30 calendar days is sufficient and adequate to provide the response, and declines to make a change.</td></tr>
<tr><td>Liberty Electric Power LLC</td><td>No</td><td>The phrase "Changes to generator unit(s), including replacements, re-ratings, and impedances" is too vague. Audit teams could read any change as a trigger. Suggested change: "following the replacement or re-rating of a generator, or following any change to a generator which results in a change in impedance".</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
The drafting team has made your suggested change.</td></tr>
<tr><td>Ameren</td><td>No</td><td>We recommend the following changes to Requirement 3-
(1) Include ‘static wire’ in the second bullet, or more simply state as ‘line impedance changes.’
(2) Include ‘bus arrangement changes’ in the third bullet.
(3) Change the fourth bullet to include ‘Additions, retirements, or changes...’ to strive for consistency for generation and transmission.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment**
1. Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.
2. The drafting team believes that “bus arrangement changes” would be included in the revised second bullet of Requirement 3, Part 3.1.
3. The drafting team believes the existing language is clear with regard to generation and respectfully declines to make the change.</td></tr>
<tr><td>Ingleside Cogeneration LP, (Occidental Chemical Corporation)</td><td>No</td><td>Ingleside Cogeneration LP believes that the coordination process developed by the project team is redundant with the one established in FAC-002-1. If there is a material change made to a Facility, the process should be captured in a single reliability standard.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
FAC-002-1 does not address Protection System coordination and the drafting team does not believe the two standards are redundant. As described in the “Description of the Current Draft,” PRC-027 is replacing PRC-001, Requirements R3 and R4.</td></tr>
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<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td>Georgia Transmission Corporation</td><td>No</td><td>1. The parenthetical comment in R3 should be deleted. R3.1 lists the items that would trigger the need for notification between entities. Once notified of modifications, the entities will communicate documentation needs.
2. R3.2: In the case of major BES equipment failure, there is a more pressing need to notify an interfacing entity that there has been change that could affect fault magnitudes. The 30 calendar days may be too long for such occurrences and 2 business days would be more in consideration.
3. R3.3.1 may interfere with PRC-004-# time schedules for misoperation follow-ups and investigations.
4. R3.3.2: Refer to comment above regarding R3.2.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
1. The drafting team believes that the parenthetical expression is beneficial to Requirement 3, but it was moved to Part 3.1 for clarity.
2. Requirement 3, Part 3.2 regards responding to a request for information required to perform a Protection System Study, not for notification of an unplanned change in the BES configuration.
3. The drafting team believes that the notifications of Requirement 3, Part 3.3 will not impact schedules for any future version of PRC-004 because the notifications take place after the corrective action has been implemented.
4. Requirement 3, Part 3.2 regards the failure of Protection System components and their replacement, not BES Elements that can change the fault duty.</td></tr>
<tr><td>Wisconsin Electric Power Company</td><td>No</td><td>1. R3 should have the phrase “shall notify...” in the requirement, not simply “shall provide ...the details”. This should be a requirement for entities to provide a notification to other entities that some changes are being planned which may affect Protection System coordination.
2. The wording in R3.1 is unclear as to the intended scope of the qualifying phrase, “when the proposed change modifies the conditions used in the coordination of</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		Protection Systems of the Interconnected Facilities." It should be made clear that ONLY those changes which affect coordination need to be communicated to other entities, whether at new or existing Interconnected Facilities or other facilities. If this is the case, then some of the comments below may not apply. 3. Also in R3.1, the bullets for "changes" in transmission systems and generators should be modified by the word "significant". Likewise, a "replacement" of an Element, or relay, or other device, may not require any change in relay settings, so the wording should be modified by "replacements which require protection setting changes". The bullet for changes to generators should also remove the "re-ratings" term, since a re-rating of a generator typically affects output power, but does not change the impedance. Indeed, there may be many minor changes which fall in the current R3.1 list which may have little or no effect on fault coordination, and therefore should not trigger a requirement for a notification or a study. Also, changes to CT or VT ratios do not necessarily result in a change in primary quantities, so these references should be removed. 4. R3.2 should be revised to require an entity making significant changes to provide the data to the other affected entities, without the need for the other entities to request it. 5. The R3.3 requirement (3.3.1 and 3.3.2) to notify other entities within 30 days for changes made following a Misoperation or failure is too restrictive. A timeframe of 60 days would be more appropriate. Also, as above, these requirements should only be applicable when the changes made have a "significant effect on coordination." A requirement to make notifications for changes unrelated to Interconnected Facility coordination will not serve the objective of increased reliability, and only increases unnecessary compliance documentation. 6. M7 (last phrase) should be revised to "...or absent such an agreement, within 30 calendar days of a request."
Response: Thank you for your comment		

Organization	Yes or No	Question 5 Comment
1. The drafting team believes that providing the details of the changes is more beneficial than just notifying of a proposed change. **2. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** **3. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** **4. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** **5. The drafting team believes that 30 days is a sufficient time to reply to provide the information on the changes.** **6. Based on your comment, Measure M6 (old M7) was modified to read, "Acceptable evidence for 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 absent such an agreement, within 30 calendar days of a request."**		
Lincoln Electric System	No	LES is concerned with the significant amount of data and information an entity would be required to share as part of R3. As an example, if a CT ratio on a secondary relay with no pilot tripping is changed, but does not change the intended response of that relay, then there is no reason to share that information simply for the sake of sharing it. Entities should be allowed some amount of discretion regarding the information to be shared amongst other entities.
Response: Thank you for your comment **The drafting team believes that communication between interconnecting entities is important for any change that modifies the**		

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<tr><td colspan="3">information previously used to comply with Requirement R2, regardless of the type of change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.</td></tr>
<tr><td>Portland General Electric Company</td><td>No</td><td>No, Add facility ratings and define transmission line impedance tolerance (see question 9 response)</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that FAC-009 already requires the sharing of Facility Ratings and their inclusion into the Protection System coordination standard is unnecessary. Your concern relating to PRC-023 is valid and may need to be addressed in FAC-009 or PRC-023.
The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.</td></tr>
<tr><td>American Transmission Company</td><td>No</td><td>ATC does not agree with the list as written and recommends the following changes:
(1) ATC suggests that Requirement 3.1 bullet 2, be revised as follows: Changes to line lengths and/or conductor size or spacing that result in significant impedance changes. As an example, an interconnected line may need to relocate a pole because of a road move. This may alter slightly the length or spacing of the line but does not result in a change to the impedance. If no impedance change occurred, no relay settings need to be changed and there should be no additional coordination.
(2) ATC suggests that Requirement 3.1 bullet 3, be revised as follows: Additions, removals, or replacements of transmission system Element(s) that is significant. An Element may be replaced with an equivalent device that does not require a relay setting change. If no relay settings need to be changed, there should be no additional coordination.</td></tr>
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<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment
1. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.
In your specific example, since the impedance did not change the drafting team believes you would not need to inform each Responsible Entity connected to the same Interconnected Element.
2. Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.</td></tr>
<tr><td>NPPD</td><td>No</td><td>Section 3.3 should clarify if the corrections change the coordination then other entities should be notified.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: “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.”</td></tr>
<tr><td>Utility Services</td><td>No</td><td>This requirement if left as is, would create a potential double jeopardy situation if a violation occurs. Under FAC-002, entities already have the obligations to communicate and coordinate the integration of new, replacement, or upgrades on existing facilities. We view this requirement to be a duplication of that standard and creates a double jeopardy situation if a violation were deemed to have occurred.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
FAC-002-1 does not address Protection System coordination and the drafting team does not believe the two standards are redundant. As described in the “Description of the Current Draft,” PRC-027 is replacing PRC-001, Requirements R3 and R4.</td></tr>
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<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td>mason</td><td>No</td><td>Do not agree with blanket inclusion of replacement of the generator step-up transformer(s) on this list.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available. It is the experience of the drafting team that modeling information will change with the replacement of a transformer.</td></tr>
<tr><td>Illinois Municipal Electric Agency</td><td>No</td><td>Illinois Municipal Electric Agency (IMEA) recommends language be included in R3 (and elsewhere if needed) to clarify the R3.1 "generator unit(s)" is not applicable to a 20 MVA or less unit or behind-the-meter generation.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
This is an issue that reaches beyond the scope of this standard and may need to be addressed through a Request for Interpretation. However, the Applicability section indicates that an entity that is registered as a Generator Owner and has Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements will need to comply with this standard.</td></tr>
<tr><td>Trans Bay Cable</td><td>No</td><td>Comments: R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
Requirement R2 requires the Transmission Owners to perform the Fault current studies because they have the necessary information to perform the studies. Requirement R1 requires all applicable entities to perform Protection System Studies. Requirement R3 requires all applicable entities to exchange the information necessary for Protection System coordination.</td></tr>
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<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td>CenterPoint Energy</td><td>No</td><td>(a) Requirement 3 includes providing schedule information and project details to generation entities. There may be established market rules that provide for what information can be shared with competitive entities.
(b) Requirements 3.1 and 3.3, with examples of what system and equipment changes require coordination, appear overly broad. Such requirements should only be “if applicable”. R3.1, for example, specifies changes in line length. Certain changes of line length are immaterial to protection system set points.
(c) R3.3 requires coordination for the replacement of failed equipment. Replacing equipment “like function-for-like function” should be excluded from this requirement.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
a. The drafting team does not believe that the requested exchange of information would violate the Standards of Conduct for an entity registered as both a GO and a TO.
b. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.
In your specific example, the drafting team believes that the entities involved can agree whether the change is significant enough to warrant an immediate review of the Protection System or whether the change could just be added to the simulation model for review as a part of the fault current assessment specified in Requirement R2.
c. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: “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.”</td></tr>
<tr><td>Duke Energy</td><td>No</td><td>(1) Revise second bullet under R3.1 as follows: “Changes to line impedance”.
(2) Add another bullet under R3.1 as follows: “Changes to breaker failure scheme</td></tr>
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<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>operating times”.
(3) Also, we don’t agree with the R3.1 Rationale that specifying a single time frame is inappropriate. A time frame similar to R3.2 should be specified. We suggest the following revised lead-in paragraph to R3.1: “According to an agreed-upon schedule or absent such an agreement, 180 calendar days prior to implementing any change or additions listed below; either at an Interconnected Facility or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities”.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment**
1. Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.
2. The drafting team believes that breaker failure scheme timers are already included from the first bullet.
3. The drafting team respectfully disagrees and declines to make your suggested changes.</td></tr>
<tr><td>South Carolina Electric and Gas</td><td>No</td><td>R3.3 in its entirety should be removed considering that all conditions covered by R3.3 are already covered by R3.1 which states: “New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios” If a correction or replacement of a protection system element is made per R3.3, this is the same thing as a modification covered under R3.1. It is noted that R4 would need to be reworded to accommodate unplanned and emergency protection system changes.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment**
The purpose of Requirement R3, Part 3.3 is to allow retroactive notification when changes are made during events such as commissioning or component failure.</td></tr>
</table>

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<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td>ExxonMobil Research & Engineering</td><td>No</td><td></td></tr>
<tr><td>Sacramento Municipal Utility District</td><td>Yes</td><td>(1) We agree with the list in R3.1.
(2) We feel that R2, R3.2 and R3.3 are unnecessary. Instead, the list in R3.1 should act as a trigger requiring both entities to document communication agreeing that coordination exists prior to putting the changes into effect. No communication under R3.3 should be required if the changes restore the system to its original state - replacing a failed relay like for like.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
1. Thank you for your support.
2. Requirement 3, Part 3.2 is associated with providing information required to perform Protection System Studies, which may be required outside of a change in 3.1. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: “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.”</td></tr>
<tr><td>Public Utility District No. 1 of Snohomish County</td><td>Yes</td><td>(1) Comments: SNPD agrees with the list in R3.1.
(2) We feel that R2, R3.2 and R3.3 are unnecessary. Instead, the list in R3.1 should act as a trigger requiring both entities to document communication agreeing that coordination exists prior to putting the changes into effect. No communication under R3.3 should be required if the changes restore the system to its original state - replacing a failed relay like for like.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
1. Thank you for your support.
2. Requirement 3, Part 3.2 is associated with providing information required to perform Protection System Studies, which may be required outside of a change in 3.1. Based on your and other comments, the drafting team revised Requirement R3, Part</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
3.3.to read: “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.”		
Dominion (this vote was changed to No, per Connie Lowe’s email with updated comment submission)	No	a). Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout the draft already address notification requirements. By using the term project scheduling this implies that detailed project information needs to be included in the information exchange. The standard should not dictate the information exchange details required and should allow the entities to determine what information is required in the exchange in order to achieve protection coordination in the appropriate timeframe. b). In R3 reword to read: “Each Functional Entity shall provide to other Functional Entities connected to an Interconnected Facility, the details of the Protection System as follows:” (It is not necessary to include (e.g. Examples) since references to these are already listed in R3-3.1.) c). In R3-3.1 reword to read: “When adding new or modifying existing Interconnected Facilities or when making changes to other facilities where the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities” d). Bullets: 1st bullet -Recommend changing reference to “protective Function settings” to “protection settings”./ 2nd bullet – Reword to read: “Line impedance changes” / 3rd bullet – Remove the word “system” e). In R3-3.3.1 change Requirement to read: “Changes found during Misoperation, commissioning, or maintenance activities that modify the conditions used in the coordination of Protection Systems. “
Response: Thank you for your comment		

Organization	Yes or No	Question 5 Comment
a. The drafting team believes it is necessary to share the pertinent scheduling information that could affect the other party. **b. The drafting team believes the current wording more correctly states the requirement.** **c. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** **d. The drafting team believes the first bullet accurately portrays the requirement's needs.** **e. Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.** **f. The drafting team combined the 3rd bullet of Requirement R3, Part 3.1 with the 2nd bullet but the drafting team did not believe that "system" needed to be removed.** **g. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "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."**		
National Grid USA / Niagara Mohawk	Yes	
Imperial Irrigation District (IID)	Yes	
Detroit Edison	Yes	
MRO NSRF	Yes	
ISO RTO Council SRC	Yes	
Progress Energy	Yes	

Organization	Yes or No	Question 5 Comment
Salt River Project	Yes	
Operational Compliance	Yes	
Pacific Gas and Electric Company	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
Idaho Power Company	Yes	
City of Austin dba Austin Energy	Yes	
Texas Reliability Entity	Yes	
Xcel Energy	Yes	
Tri-State G & T	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
Platte River Power Authority	Yes	
MWDSC	Yes	

Organization	Yes or No	Question 5 Comment
ATCO Electric	Yes	
El Paso Electric Company	Yes	
Clark Public Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
El Paso Electric	Yes	

6. In Requirement R4, the SDT required that agreement must be reached prior to implementation of proposed Protection System changes except under the conditions identified in Requirement 3, Part 3.3. Do you agree with this need? If not, please specify reasons in the comment area.

Summary Consideration:

A majority of commenters concurred with the need for entities to confirm agreement of Protection System coordination prior to implementing changes. Several commenters expressed a desire to see the standard drafting team develop and include a conflict resolution process for situations where mutual agreement cannot be reached. The drafting team responded with the following: The drafting team believes that any conflict resolution should be handled through normal company practices.

Several commenters expressed concern that Requirement 4 seemed to mandate agreement without provision for the entity receiving study results to express disagreement and suggest modifications or compromise. Also some commenters disagreed with the time frames associated with Requirement 4, suggesting lengthening them and/or including a provision for an otherwise agreed-upon schedule. Others suggested the "prior to implementation" was appropriate without specifying any particular time period. Based on comments, the drafting team revised Requirement R4, Parts 4.1 and 4.2, and removed Part 4.3. The responses are as follows: Based on comments, the drafting team revised Requirement R4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."

Some commenters suggested the requirement refer to entities confirming "acceptance" rather than confirming "agreement". Others suggested the requirement refer to agreeing that coordination is achieved or maintained prior to implementing changes, rather than requiring agreement with the changes themselves. Based on these comments, the drafting team revised Requirements R4, Parts 4.1 and 4.2 as noted above.

Organization	Yes or No	Question 6 Comment
Southwest Power Pool NERC Reliability Standards	No	1. We agree with the need but feel it needs to be more detailed to include wording that would address that the coordinated owner has all appropriate data to

Organization	Yes or No	Question 6 Comment
Development Team		perform the study before his 30 day timeline begins. 2. We would also like to see a conflict resolution process included under this requirement.
Response: Thank you for your comment. **1. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.** **2. The drafting team believes that any conflict resolution should be handled through normal company practices.**		
Pepco Holdings Inc. & Affiliates	No	1) 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

Organization	Yes or No	Question 6 Comment
		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? 2) Requirement R4.3 requires confirmation of agreement within 30 days of being notified of corrections made due to as found setting errors or emergency replacements of Protection System components. Again, what if the changes are not acceptable to the other party? Which entity is found not compliant, the one who proactively made the changes or the one who won't confirm agreement? This is the 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. 3) 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 some outlet for a dispute resolution process seems unfair to either party. As such, we suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined above.

Response: Thank you for your comments.

1. **The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting team cannot make judgments on compliance.**
2. **The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting**

Organization	Yes or No	Question 6 Comment
team cannot make judgments on compliance. **3. The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting team believes Requirement R4 is an integral part of the standard and must remain.**		
Luminant	No	Luminant agrees with the need to reach an agreement on relay coordination based on the specific circumstances in R3.3.1 and R3.3.2. However, the time period to reach agreement of 30 days should be replaced with an agreed upon time schedule by all parties.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Bonneville Power Administration	No	In many cases, one party of the interconnection is simply implementing the protection system changes provided by the other entity. Requiring the agreement of this party implies that the entity understands what is going on and is not a practical use of time and resources.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Detroit Edison	No	Recommend that if protection system changes due to emergencies need not be agreed upon before installation, then this should be stated more directly in the standard.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td>Western Small Entity Comment Group</td><td>No</td><td>R4.1 as written apparently requires receiving entities to always agree with the initial study, even if they see flaws that would lead to miscoordinating Protection Systems. Suggest that “confirm” be replaced with “reach.”</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>MRO NSRF</td><td>No</td><td>1) The NSRF agrees in general but questions how to handle situation where neighboring utility are unable or unwilling to meet required timetable? Recommend the SDT explain the process for conflict resolution.
2) Requirement 4.2 seems to mandate agreement with proposed changes which seems to go beyond the scope of the standard which is stated as “to coordinate Protection Systems”. It is suggested that this requirement be rewritten to require agreement that proper coordination will be maintained when the changes are implemented.
3) In a similar way requirement 4.3 should be rewritten.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team believes that any conflict resolution should be handled through normal company practices.
2. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”
3. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.</td></tr>
<tr><td>PPL Corporation NERC</td><td>No</td><td>See comment in question #1 above.</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
Registered Affiliates		
Response: Thank you for your comment. **Please see the drafting team response to your comment in Question 1.**		
Colorado Springs Utilities	No	This requirement seems to create a paper work burden that will add cost and lengthen the process of any and all transmission changes, unless there is some size significance added to the requirement under which a reduced process is involved. The maximum amount of paper work to complete must be assumed, unless there are specific limits set to restrict an overreach in how the regulation is applied.
Response: Thank you for your comment. **The drafting team believes the scope of a particular project will dictate the work necessary to coordinate the Protection Systems involved, and to document the coordination process.**		
Associated Electric Cooperative, Inc., JRO00088	No	PRC-027-1 R4.2 change: Replace: “that Protection Systems(s) changes” With: “each related Protection Systems(s) change “Rationale: AECI sympathizes with the need for agreement, and believes that to be the necessary goal. However, this requirement indicates all-or-none for notified Protection System Change(s). Entities may agree on most all communicated changes, and yet a more complicated change, particularly outside of Zone 1, may require some interim compromise, or that one particular (backward-looking) be excluded until agreement is reached. Full agreement, prior to placing facilities into service, might otherwise become a method for forcing a poor compromise on protective settings.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s)**		

Organization	Yes or No	Question 6 Comment
associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."		
Southern Company	No	If there is a requirement to agree, what happens if there is no agreement. There must be a resolution process.
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal company practices.**		
Independent Electricity System Operator	No	We agree with the need to provide an agreement to the study results and to confirm acceptability of the proposed changes (other than those conditions identified in Requirement 3, Part 3.3), but R4 is unclear in a number of aspects, as follows: 1. 4.1 There is no requirement or provision for the receiving entities to express disagreement, with rationale, and R4 does not require resolving the differences. Both need to be added. 2. 4.2 Based on the language in Part 4.1, we assume R4 applies to the receiving entities. Hence we interpret 4.2 to require the receiving entities to confirm with the sending (or the initiating) entities of their agreement with the proposed changes. In that vein, the wording in 4.1 "confirm the affected Interconnected Facility owners" is unclear as to who needs to confirm with whom. Suggest to reword 4.1 to:"Prior to the in-service date of any planned change at the Interconnected Facility, confirm with the Interconnected Facility owners that initiated the changes that agreement with the Protection System(s) changes as described in Requirement R3, Part 3.1. was reached." 3. 4.3 requires that the receiving entities confirm with the initiating entities of the changes made under Part 3.3, for which prior agreements are not necessary or perhaps possible. However, there is no requirement or provision for the receiving entities to express a disagreement, with rationale, and suggest alternative setting

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>changes, or resolve the differences. This needs to be provided.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”
2. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”
3. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.</td></tr>
<tr><td>American Electric Power</td><td>No</td><td>The 90 Day window will not be sufficient during the initial R1 time frame. AEP suggests 180 days during the R1 compliance window.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>City of Austin dba Austin Energy</td><td>No</td><td>Austin Energy (AE) agrees with the need to coordinate Protection System changes; however, AE believes R4.2 is not sufficiently clear. As written, one could interpret it to mean that a Facility owner must obtain consent on the changes listed under R3.1, not just the Protection System changes (such as relay settings). AE does not believe it appropriate to require a Facility owner to gain consent on the actual change to the Facility itself (such as changes to line lengths/conductor size or replacement of transmission system Element(s), generator units or generator step-up transformer).The Guidelines and Technical Basis (p 20 of PRC-027-1 Draft #1) states, “The purpose of this requirement is to assure the effects</td></tr>
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<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>that planned changes have on Protection Systems at Interconnected Facilities have been considered by all affected entities.” AE agrees with this concept and believes the SDT sufficiently covers it through R1.1.3 and R4.1. AE recommends striking R4.2 from the Standard.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s)associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”</td></tr>
<tr><td>LCRA Transmission Services Corporation</td><td>No</td><td>Each Transmission Owner, Generator Owner, and Distribution Provider shall:
4.1. Within 90 calendar days after receipt, confirm acceptance with the summary results of a Protection System Coordination Study, as described in Requirement R1, Part 1.2.
4.2. Prior to the in-service date of any planned change at the Interconnected Facility, confirm the affected Interconnected Facility owners accept the Protection System(s) changes, as described in Requirement R3, Part 3.1</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1.   Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”
2.   Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”</td></tr>
<tr><td>Tri-State G & T</td><td>No</td><td>We believe that there are many instances of changes that can made to Protection Systems as required in Requirement 3, Part 3.1 that don’t require coordination between entities but that might be interpreted that the change “modifies the</td></tr>
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<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>conditions used in the coordination of Protection Systems.” Examples are load encroachment settings, communication port settings, etc. We think language needs to be added with regard to “... modifications that impact the coordination of Protection Systems between entities, of: ...” in the first bullet, if confirmation from the other entity is required.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that any change(s) noted in Requirement R3, Part 3.1 at the Interconnected Element needs to be communicated with the other entity.</td></tr>
<tr><td>Ingleside Cogeneration LP, (Occidental Chemical Corporation)</td><td>No</td><td>In general, Ingleside Cogeneration LP believes that a material unplanned change must be communicated to neighboring Facility Owners. However, this should not include an emergency replacement in kind due to a failure. This is a repair only which does not change the characteristics of the relay or the associated BES components - and therefore has no impact on interconnected owners.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes this information must be communicated.</td></tr>
<tr><td>Wisconsin Electric Power Company</td><td>No</td><td>The requirement to reach agreement on Protection System changes prior to the project in-service date is not realistic and should be removed. While the entity that is initiating a project has a responsibility under R3 to notify other entities in order to perform a study, there is no required timeframe for these notifications to occur. Unless the initiating entity has a requirement to provide data under R3 in a timeframe sufficiently ahead of the in-service date, this is a requirement that may be impossible to achieve.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that proposed modifications to Interconnected Elements, as described in Requirement R3, Part 3.1,</td></tr>
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<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">must be communicated and agreed to prior to the in-service date. This would include communication of project schedules developed relative to a project’s scope. However, 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 for a particular project. Further, the drafting team believes the entity initiating the project has incentive to consider provision of, and response to Protection System coordination issues be considered within the project schedule.
Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”</td></tr>
<tr><td>Dairyland Power Cooperative</td><td>No</td><td>How is it to be handled if two entities do not agree to the same approach?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that any conflict resolution should be handled through normal company practices.</td></tr>
<tr><td>Portland General Electric Company</td><td>No</td><td>No, see question 9 response</td></tr>
<tr><td>NPPD</td><td>No</td><td>Recommend the drafting team should consider several scenarios to help determine issues that will arise with putting into practice this standard with the time lines included. Some scenarios I can think of are:
1. who is liable or fineable if a required approval reply for a protection study is not made in a timely manner to a Transmission owner. It is imperative not to hold a utility responsible for another entities lack of timely responses. These issues will create murky situations when the Transmission owner does not have control over external entities ability to respond to notifications of changes within specified times.
2. If a Distribution Provider is not registered is the Transmission owner responsible for getting a reply or approval of a protection study?</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
1. The drafting team cannot make compliance judgments. Additionally, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.” **2. The standard is only applicable to the registered entities listed in the Applicability section of the standard.**		
Utility Services	No	See comment to Question 5.
mason	No	Each entity has its own philosophy and standards for Protection System design. In providing agreement to a third party design, a question of liability is also opened up. R4 should be changed from requiring agreement to requiring notification. There is enough incentive for entities to resolve material disagreements on Protection System design without the need for regulatory intervention. Regulatory involvement should only take place when business conditions call for it. Otherwise the result is higher production costs with no reliability benefit.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”**		
Trans Bay Cable	No	Comments: R4.1 as written apparently requires receiving entities to always agree with the initial study, even if they see flaws that would lead to miscoordinating Protection Systems. Suggest that “confirm” be replaced with “reach.”
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”**		
Clark Public Utilities	No	1. The proposed Requirement R4 is not an acceptable method of confirming

Organization	Yes or No	Question 6 Comment
		agreement among parties. Requirement 4.1 requires an entity to agree with the proposed changes within 90 calendar days. What if the entity thinks the proposed changes are wrong? Other standards that require entity A to provide information to entity B provide that entity B will provide written comments to entity A within a specified period of time. 4.1 should state the following: “Within 90 calendar days after receipt, provide written comments (if any) regarding the summary results of a Protection System Study, as described in Requirement R1, Part 1.2.” 2. Requirement 4.2 will require an entity needing to implement a planned change to delay the in-service date until affected entities agree with the proposal. This sets up a potential stand-off with no method of resolution. In other standards where parties provide comments the entity is required to respond to those comments within a specified period of time. However, 4.2 as worded would stop the implementation until the other parties all agree. The owner of the facility needs to have ultimate and sole control for implementing these changes and the current 4.2 would stop a project dead in its tracks until the other parties all agreed. Proceeding without this agreement would result in a standard violation and imparts power upon entities over facilities they do not own. 4.2 should state the following: “Within 30 calendar days after receipt of any written comments received per Requirement 4.1 and prior to the in-service date of any planned change at the Interconnected Facility, respond to such written comments.”

Response: Thank you for your comment.

1. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”**
2. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”**

Organization	Yes or No	Question 6 Comment
Oncor Electric Delivery Company LLC	No	Oncor believes agreements must be reached; however, there needs to be some definitions in the Standard to define the exact meaning of the term "agreement". In addition, the sub requirements 4.3.1 and 4.3.2 calls for confirmation of the Protection System changes are acceptable pursuant to notification received in Requirement 3, within 30 days, however the sub requirements provide no mechanism for resolution in the event the changes are not acceptable to the receiving entity within 30 days of receipt. Oncor suggest that these two sub requirements be removed. There are sufficient checks and balances under 4.2 to provide coverage for any disagreement between entities without the need to self-report under the 4.3.1 and 4.3.2 if an agreement cannot be reached within 30 days of receipt.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
ExxonMobil Research & Engineering	No	
Northeast Power Coordinating Council	Yes	What happens when consensus is not reached between two parties? The TO should have the responsibility for coordination.
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal company practices.**		
ACES Power Marketing Standards Collaborators	Yes	Yes, we agree. The application guidelines were particularly helpful in explaining how the Requirements R3 and R4 work together.
Response: Thank you for your comment.		

Organization	Yes or No	Question 6 Comment
Operational Compliance	Yes	We suggest that R4.1, R4.3.1 and R4.3.2 all have a time period of 90 days.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Sacramento Municipal Utility District	Yes	We agree that the entities should agree prior to any changes being implemented. The only date of interest, in our opinion, is the in-service date of any proposed changes. If agreement is reached prior to the field changes being made, then that is all that matters.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
Xcel Energy	Yes	1. Conceivably, there could be non-reliability based reasons why an entity might not provide concurrence. An alternate avenue should be considered as allowable, such as the requesting entity working through the RC to obtain response from a non-responsive entity. 2. Similar comments on measure M9 as contained in item 3 above on measure M2. 3. Measure M9 does not account for non-acceptance under R4.3 or R4.1 as restudy or expanded studies may be required and result in a M9 violation.
Response: Thank you for your comment. **1. The drafting team believes that any conflict resolution should be handled through normal company practices.** **2. Acceptable evidence that response was provided could be registered mail confirming receipt at an address. Additional acceptable evidence would be letters, or emails acknowledging receipt.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">3. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>Exelon</td><td>Yes</td><td>Comments: Although not stated explicitly, this question seems to be asking about R4, Part R4.2. Exelon agrees that concurrence should be reached prior to the in service date for Protection System changes that result from the equipment changes at an Interconnected Facility as described in R3, Part3.1.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.</td></tr>
<tr><td>Duke Energy</td><td>Yes</td><td>1. We support the necessity for agreement, but there can be differences in philosophies that make reaching agreement difficult. How are disagreements to be handled?
2. As the requirement is currently worded, the entity receiving the study has no alternative but to agree within the specified timeframes.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team believes that any conflict resolution should be handled through normal company practices.
2. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>Dominion</td><td>Yes</td><td></td></tr>
<tr><td>National Grid USA / Niagara Mohawk</td><td>Yes</td><td></td></tr>
<tr><td>Hydro One</td><td>Yes</td><td></td></tr>
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Organization	Yes or No	Question 6 Comment
Imperial Irrigation District (IID)	Yes	
Santee Cooper	Yes	
SERC Protection and Control Subcommittee	Yes	
ISO RTO Council SRC	Yes	
Tennessee Valley Authority	Yes	
GP Strategies	Yes	
Kansas City Power & Light	Yes	
Salt River Project	Yes	
Pacific Gas and Electric Company	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Idaho Power Company	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 6 Comment
Liberty Electric Power LLC	Yes	
Ameren	Yes	
Georgia Transmission Corporation	Yes	
NV Energy	Yes	
Platte River Power Authority	Yes	
MWDSC	Yes	
American Transmission Company	Yes	
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
El Paso Electric Company	Yes	
South Carolina Electric and Gas	Yes	
El Paso Electric	Yes	
FirstEnergy		No answer or comment at this time.
Public Service Enterprise		a. In R4 overall, we concur that agreement does need to be reached before changes

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td>Group</td><td></td><td>can be implemented; however, if there is a disagreement that cannot be resolved by the parties within the time frames specified, a dispute resolution process should be invoked. Otherwise, if an owner disagrees with another owner’s results, it has no option but to agree or face a violation of the standard for failing to do so.
b. The specific requirement in the question is in part 4.2, not R4. The list of items in R3.1 appeared reasonable. But R4.2 requires agreement to be reached “prior to the in-service date” under R4.2. Allowing agreement to be reached prior to the in-service date could allow one party to unreasonably hold up the schedule. It should be stated as follows: “Within 90 days after receiving the planned changes at the Interconnection Facility, the affected Interconnection Facility owners shall either agree with the changes, or propose alternative changes, stating why such changes are desirable. Failure to provide a response will constitute agreement with the planned changes by the non-responding Interconnecting Facility owner.”</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
a. The drafting team believes that any conflict resolution should be handled through normal company practices.
b. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”</td></tr>
<tr><td>Public Utility District No. 1 of Snohomish County</td><td></td><td>Comments: SNPD agrees that the entities should agree prior to any changes being implemented. The only date of interest, in our opinion, is the in-service date of any proposed changes. If agreement is reached prior to the field changes being made, then that is all that matters.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”</td></tr>
</table>

7. In Requirement R4, the SDT established a 90 day time frame for responding to a request for agreement with a Protection System Study. Do you agree with this time frame? If not, please provide specific suggestions with your reasoning(s) in the comment area.

Summary Consideration:

The responses were equally split between agreeing and not agreeing with the 90 day time frame. Some comments wanted a longer time frame due to resource issues while others preferred a shorter time frame to prevent potential project delays. The drafting team decided not to make any changes to the time frame and responded as such: The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Element(s) to review the summary results of a Protection System Study.

There were several comments which suggested changes to the requirements. The responses included one or more of the following:

- Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."
- Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."
- Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.

Several responses involved the need for a resolution process in cases that agreement could not be reached. The drafting team responded to these comments as follows: "The drafting team believes that any conflict resolution should be handled through normal company practices".

Organization	Yes or No	Question 7 Comment
Pepco Holdings Inc. & Affiliates	No	We suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined in our response to Question 6.
Response: Thank you for your comment.		

Organization	Yes or No	Question 7 Comment
Based on comments, the drafting team did extensively rewrite Requirement R4 including removing Requirement R4, Part 4.3.		
Luminant	No	Luminant recommends that the time frame should be "according to an agreed-upon documented schedule between Transmission Owner, Generation Owner, or Distribution Provider. Luminant would recommend the removal of the 90 day requirement. 90 days may not fit all circumstances. It should be left between the parties to determine the timeline of the project and reaching agreement. This is what should be documented to ensure coordination of activities between the affected parties.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Imperial Irrigation District (IID)	No	120 calendar days are suggested instead of 90 because verification of Protection System Study needs to be performed before an agreement can be made and it is time consuming.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Bonneville Power Administration	No	BPA believes that requiring an agreement from all parties could prevent the implementation of emergency changes.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.

Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.</td></tr>
<tr><td>Detroit Edison</td><td>No</td><td>It appears that the “initiator” has 90 days after completing the study to provide the information while the other entity has 90 days to review and respond to the request. Suggest that a longer response time frame be considered since the “responder” may need significant time to review changes.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>PPL Corporation NERC Registered Affiliates</td><td>No</td><td>See comment in question #1 above.</td></tr>
<tr><td>Colorado Springs Utilities</td><td>No</td><td>Due to construction schedule requirements a 30 day approach should be taken.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>Tennessee Valley Authority</td><td>No</td><td>There may be instances where extenuating circumstances delay agreement beyond 90 days. For long lead time or complex protection scheme projects requiring more</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td></td><td></td><td>interaction between protective relaying engineers, exceeding the 90 day period could be acceptable to the entities involved. Evidence of mutual agreement on an extension beyond 90 days should be acceptable.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**

The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>ACES Power Marketing Standards Collaborators</td><td>No</td><td>We assume this question refers to Part 4.1. While we do not see any issues with the 90 day requirement, Part 4.1 needs to be modified to reflect what a responsible entity must do if they do not agree. As written any other response than agreement is a violation. Thus, if a TO indicates it disagrees with the results of the Protection System Study (PSS) within 90 days, it technically is in violation of the requirement. The application guidelines explain that absent agreement the revisions should be proposed. We agree with this approach but the requirement simply does not say this. It should.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**

The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>These can be matters of extreme complexity in design, implementation and operation. Stipulating that 90 days (Requirement 4.1) and 30 days (Requirement 4.3) is sufficient time to come to an agreement is presumptuous and is not necessary. Requirements 4.1 and 4.3 should stipulate that entities in receipt of proposed</td></tr>
</table>

Organization	Yes or No	Question 7 Comment
		changes to relay protection system(s) or component(s) be evaluated and responded to by the entity in receipt. The response could be agreement or non-agreement with concerns or objections noted in the response.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." The drafting team also combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Southern Company	No	Within "90 calendar days after receipt, confirm agreement" vs. "90 day time frame for responding to a request". Acknowledgement of the receipt and review of a change should be the limit here - agreement with the settings should not be required.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Salt River Project	No	This is too long; 60 days should be adequate
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		

Organization	Yes or No	Question 7 Comment
Pacific Gas and Electric Company	No	12 month time frame may be required to resolve the technical issues that typically prevent agreement
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Western Area Power Administration	No	See general comments below (#9).
American Electric Power	No	AEP has suggested adjusting the time requirements, as stated in Question 3 and 7. These time requirements should be included and the VSLs should be scaled accordingly.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Sacramento Municipal Utility District	No	No, we do not agree. R4.2 should apply here. R4.1 and R4.3 should be eliminated. If one entity proposes making settings changes, then agreement must be reached prior to implementing the changes. We feel all these timelines are unnecessarily burdensome to remember and quite arbitrary. If one entity believes it cannot get another entity to respond or to reach agreement on coordination, they can always ask their RE for assistance in maintaining the reliability of the system. Since all these activities occurred long before the mandatory standards existed and are covered

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td></td><td></td><td>under the present PRC-001, we do not feel the REs will be swamped with calls if R4.1 and R4.3 are eliminated.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.” Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”</td></tr>
<tr><td>City of Austin dba Austin Energy</td><td>No</td><td>Austin Energy (AE) believes that 90 days is sufficient for responding to summary results of a Protection System Study, but it is not always sufficient for completing the iterative discussions that often take place to resolve questions and potential concerns. The Guidelines and Technical Basis (p19 of PRC-027-1 Draft #1) states, “R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to confirm agreement with the summary results of a Protection System Study ...; or absent such agreement, propose revisions to achieve acceptable results.” AE asks the SDT to include this “absent such agreement” concept in R4.1 and extend the timeline to accommodate such revisions to one that is mutually agreed upon by the impacted parties.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>Manitoba Hydro</td><td>No</td><td>This 90 day time frame may be too long, since an agreement is required from the</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td></td><td></td><td>interconnecting parties before the proposed protection changes can be implemented.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>Exelon</td><td>No</td><td>This question differs from what is required in the language in the draft standard. In Requirement R4.1, the 90 days allowed is for entities to “confirm agreement” with the summary. If an entity must only respond at the end of 90 days, the response could be that they disagree. In this case, discrepancies must be resolved at the cost of more time. Regardless, allowing 90 days for an entity to respond before an entity can proceed with design could cause serious delays to engineering and design processes. However, until we know what is required by a Protection System study, Exelon cannot offer a suggestion for a suitable timeframe for R4.1. SDT should specifically justify the proposed 90-day time frame. Since, a 90-day time frame may not be sufficient to compile all the required design data and results for Protection System Study (PSS) and to verify the Protection Systems are coordinated within the applicable entities.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>Tri-State G & T</td><td>No</td><td>We think 60 days is more appropriate. For the receiving party, 30 days may be too short, and for the sending party 90 days may be too long.</td></tr>
</table>

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Liberty Electric Power LLC	No	Smaller entities do not have the staff resources to respond, and must bid, contract, and receive a report. Further, they must also go through a process to allocate the funds. 180 days at a minimum, but ideally a longer period should be in place to allow for the budget process.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Public Utility District No. 1 of Snohomish County	No	Comments: SNPD does not agree. R4.2 should apply here. R4.1 and R4.3 should be eliminated. If one entity proposes making settings changes, then agreement must be reached prior to implementing the changes. We feel all these timelines are unnecessarily burdensome to remember and quite arbitrary. If one entity believes it cannot get another entity to respond or to reach agreement on coordination, they can always ask their RE for assistance in maintaining the reliability of the system. Since all these activities occurred long before the mandatory standards existed and are covered under the present PRC-001, we do not feel the REs will be swamped with calls if R4.1 and R4.3 are eliminated.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after**		

Organization	Yes or No	Question 7 Comment
receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."		
Platte River Power Authority	No	We believe the agreement must be reached prior to implementing the changes. This requirement is burdensome on the entity for record keeping and does not add reliability to the BPS.
Response: Thank you for your comment. **Based on comments, the drafting team did extensively rewrite Requirement R4 including removing Requirement R4, Part 4.3.**		
MWDSC	No	More time than 90 days may be needed to reach agreement for complex system changes or because of conflicting study priorities. Allow more flexibility for the parties to agree to a time, not to exceed, e.g. 180 days.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Portland General Electric Company	No	No, It depends upon what constitutes a Protection System Study (see question 9 response
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1,**		

Organization	Yes or No	Question 7 Comment
Part 1.2, and respond as to whether further action is required.”		
American Transmission Company	No	1) ATC does not agree with the 90 day time frame. 2) ATC also has the following recommendation: Requirement 4.2 states that Interconnected Facility Owners confirm that coordination is agreed to prior to placing equipment in-service. ATC believes that R4.2 is adequate to cover coordination. Therefore, the SDT should strike R4.1 and R4.3.
Response: Thank you for your comment. **1. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”** **2. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”**		
NPPD	No	This requirement does not allow for various scenarios or conditions in the process of doing business. For example, multiple phased work or longer lead time projects where designs may change. It would be better that there be verification that studies were performed prior to in-service dates rather than tracking detailed time lines which could likely be complex and difficult to judge for audit start and end dates.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td>mason</td><td>No</td><td>Do not agree with the need for documentation of "agreement with a Protection System Study" between entities. See Question 6 response.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>El Paso Electric Company</td><td>No</td><td>1) EPE believes the timelines are not adequate when coordinating protection system studies involving sequential interdependence among parties for interconnected facilities. Timing of study data should correlate with any written agreements or procedures agreed to between the various parties. EPE also believes the documentation requirements within this draft Standard slow down the process, therefore increasing the time needed to complete and communicate the study data.
2) Additionally, the proposed Standard fails to address two important and likely types of situations:
(a) the situation in which an interconnected entity fails to respond to study results or to a planned change at the Interconnected Facility, or
(b) the situation in which disagreements between the entities are not resolved within the proposed Standard’s time clock.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
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<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td colspan="3">2. The drafting team believes that any conflict resolution should be handled through normal company practices.</td></tr>
<tr><td>El Paso Electric</td><td>No</td><td>1) EPE believes the timelines are not adequate when coordinating protection system studies involving sequential interdependence among parties for interconnected facilities. Timing of study data should correlate with any written agreements or procedures agreed to between the various parties.
2) EPE also believes the documentation requirements within this draft Standard slow down the process, therefore increasing the time needed to complete and communicate the study data. The proposed Standard fails to address two important and likely types of situations:
(a) the situation in which an interconnected entity fails to respond with study results or to a planned change at the Interconnected Facility, or
(b) the situation in which disagreements between the entities are not resolved within the proposed Standard’s time clock.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”
2. The drafting team believes that any conflict resolution should be handled through normal company practices.</td></tr>
<tr><td>ExxonMobil Research & Engineering</td><td>No</td><td></td></tr>
<tr><td>Utility Services</td><td>No</td><td></td></tr>
<tr><td>National Grid USA / Niagara Mohawk</td><td>Yes</td><td>1) In the event that someone hands you a study of their entire system or of all their interconnections you should only be responsible for reviewing study results for those interconnections in which you are a participant.</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td></td><td></td><td>2) Furthermore, what if you don’t agree with the study results you’ve been handed? The text as written literally commands you to agree with them! The text should be reworded to require a response (not necessarily agreement) within 90 days and relative only to the portion of the study applicable to interconnections you participate in.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team believes the purpose and applicability sections of the standard support your conclusion.
2. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>Yes</td><td>For studies of an entire system or all of its interconnections, those persons doing the study should only be responsible for reviewing the study results for those interconnections in which they participate. The wording in the text demands that the results be agreed with. The text should be reworded to require a response (not necessarily agreement) within 90 days and only pertain to the portion of the study applicable to interconnections participated in.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The drafting team believes the purpose and applicability sections of the standard support your conclusion. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>Associated Electric Cooperative, Inc., JRO00088</td><td>Yes</td><td>These facilities take time and budget to build or implement, and so 3-months prior to field-changes seems reasonable.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td>Idaho Power Company</td><td>Yes</td><td>Yes, There appears to be no mechanism in the Requirement addressing if coordination changes are not acceptable. This should be addressed as 90 days could easily be exceeded in this scenario.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>South Carolina Electric and Gas</td><td>Yes</td><td>1) R4.1 only mentions R1.
2) R4.2 should be reworded to make it clear that entities have 90 days to respond to proposed protection system changes received per R3.1. The concern is that with no specified time the responding entity can delay the initiating entity’s schedule even if the protection system changes were shared well in advance of the in service date.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. Requirement R4, Part 4.1 is intended to only reference Requirement R1.
2. The drafting team acknowledges your concern and believes the concern you raise would need to be handled through normal company practices.</td></tr>
<tr><td>Dominion</td><td>Yes</td><td>Reword R4., 4.3 to read: <u>“Within 30 calendar days after receiving notification of:”</u></td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.</td></tr>
</table>

Organization	Yes or No	Question 7 Comment
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
Hydro One	Yes	
Santee Cooper	Yes	
Western Small Entity Comment Group	Yes	
MRO NSRF	Yes	
SERC Protection and Control Subcommittee	Yes	
ISO RTO Council SRC	Yes	
GP Strategies	Yes	
Operational Compliance	Yes	
Independent Electricity System Operator	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Texas Reliability Entity	Yes	
LCRA Transmission Services	Yes	

Organization	Yes or No	Question 7 Comment
Corporation		
Xcel Energy	Yes	
Tacoma Power	Yes	
Ameren	Yes	
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	Yes	
Georgia Transmission Corporation	Yes	
Wisconsin Electric Power Company	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
Trans Bay Cable	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 7 Comment
Clark Public Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
FirstEnergy		No answer or comment at this time.
Public Service Enterprise Group		See our response to #6 above, paragraph a.

8. The team included VRFs, VSLs, and Time Horizons with this posting. Do you agree with the assignments? If not, please provide specific suggestions for change.

Summary Consideration:

In general, most commenters agreed with the VRF assignments and about half of the commenters agreed with the VSLs assignments. Those commenters that disagreed with several of the assigned VSLs stated that they were too stringent, or escalated too rapidly. Several commenters wanted consistency regarding the time frames established for tardiness.

The drafting team responded that they had assigned the VRFs and written the VSLs in accordance with the guidance established by NERC and FERC, and that the VSLs were assigned based upon the significance of the individual requirement parts to the overall coordination process. The drafting team made no changes to the VRFs; however, the following changes were made to the VSLs:

- For Requirement R1, Part 1.1.2, the time period for tardiness in the ‘Lower’ VSL was lengthened from 10 days to 30 days.

One commenter suggested adding Long-term Planning to the Time Horizon for Requirement R3. The drafting team agreed and made the suggested change.

Organization	Yes or No	Question 8 Comment
Luminant	No	Based on the comments on Q6, the VSL would need to be modified. Q7 and 9, the VSLs would change accordingly to accommodate an agreed-upon time frame for acceptable relay coordination and a method for resolving issues surrounding obtaining an acceptable coordination where differences occur.

Response: Thank you for your comment.

The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team’s intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 8 Comment</th></tr>
<tr><td>Bonneville Power Administration</td><td>No</td><td>BPA believes that in general, the VRFs and VSL’s are too high.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team assigned the VRFs in accordance with the NERC criteria and FERC guidelines for establishing VRFs, and believes the assigned risk factors are appropriate.</td></tr>
<tr><td>Santee Cooper</td><td>No</td><td>The 10 day VSLs are too restrictive in R1.1.1. VSL times should be similar for all requirements. Suggest dates should be as follows: Lower - 30 days late, Moderate - more than 30 days, less than a year, High - more than a year, but completed, Severe - more than a year or not done.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team’s intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.</td></tr>
<tr><td>Detroit Edison</td><td>No</td><td>The proposed VSL for R4 appears to imply that the “receiving” entity has no other choice but to confirm agreement. If the “receiving” entity has concerns with the study or changes, both parties should be responsible for resolving the issues.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes your comment pertains to Requirement R4 and not the VSL. Requirement R4 does require the receiving entity to confirm agreement within a set time frame. The VSL defines the degree of non-compliance with the requirement.</td></tr>
</table>

Organization	Yes or No	Question 8 Comment
Western Small Entity Comment Group	No	We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in “guidelines and Technical Basis” that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team’s intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
PPL Corporation NERC Registered Affiliates	No	See comment in question #1 above.
SERC Protection and Control Subcommittee	No	We recommend a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale, this urgency is not warranted. Most entities will have numerous Interconnection Facilities, so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: o Lower VSL should be 30 days late. o Moderate VSL should be more than 30 days, less than a year. o High VSL should be more than a year but done. o Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs; and believes the VSL for Requirement 1, Part 1.1.1 is correctly assigned. The drafting team modified Requirement 1, Part 1.1.1 to 48 months from 36**		

Organization	Yes or No	Question 8 Comment
months. The VSLs are written specific to an individual requirement and define the degree to which compliance with the requirement was not achieved; consequently, a consistent set of VSL time frames across all requirements may not be appropriate. The drafting team strives for consistency in assignment of VSLs throughout the standard.		
Colorado Springs Utilities	No	If the requirements are not reasonable, the VRFs and VSLs are also not reasonable.
Response: Thank you for your comment.		
Tennessee Valley Authority	No	We recommend a consistent set of VSL timeframes across all requirements. The 10 day limits are unreasonable and, as stated in the R1.1.1 rationale, this urgency is not warranted. Most entities will have numerous Interconnection Facilities, so applying these VSLs to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: o Lower VSL should be 60 days late. o Moderate VSL should be more than 60 days, less than a year. o High VSL should be more than a year but done. o Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Associated Electric Cooperative, Inc., JRO00088	No	See SERC PCS Comments.
ACES Power Marketing Standards Collaborators	No	(1) The time horizon for R2 should only be Long-term Planning. The study has to be completed every 24 months and while notification in Part 2.3 has to occur within 30

Organization	Yes or No	Question 8 Comment
		days it is only after that the study to satisfy the 24 month time period is complete. (2) Requirement R3 should include Long-term Planning. Transmission system expansions would be covered under Part 3.1. (3) The VSLs for Requirement R1 are gradated based on the number of days late the requirement is met for Part 1.1 but not Part 1.2. It seems Part 1.2 should have similar gradated VSLs. (4) For Requirement R4, we suggest the VSL for Part 4.2 should clearly state that any changes made during extreme operating circumstances (i.e. extreme weather) are excluded. This is essentially a question on what is meant by "planned". Are changes made to restore service in a hurricane or tornado damaged area a few days after the devastation planned? We think they are not but see how auditors could view the changes as planned particular if any level of study was required.

Response: Thank you for your comment.

The Time Horizon is a compliance element and is used as a factor in determining the size of a sanction. If an entity violates a requirement and there is no time to mitigate the violation because the requirement takes place in real-time, then the sanction associated with the violation is higher than it would be for violation of a requirement that could be mitigated over a longer period of time.

1. **The drafting team respectfully disagrees and believes the time horizons are appropriate and consistent with the criteria for establishing time horizons: Long-term Planning — a planning horizon of one year or longer... Operations Planning — operating and resource plans from day-ahead up to and including seasonal.**
2. **The drafting team agrees and will make the suggested change to Requirement R3.**
3. **Please review the VSLs. Requirement 1, Part 1.2 is already gradated.**
4. **The notification of unplanned changes (for circumstances as you describe) are covered by Requirement 3, Part 3.3. The drafting team has removed the requirement for parties to reach agreement (Requirement R4, Part 4.3).**

Organization	Yes or No	Question 8 Comment
Kansas City Power & Light	No	The 10 day increments represent a 5% error and considering this is a six month requirement. The 10 day increment represents 4 - 6 working days across 2 weekends and including a holiday. Recommend the increments be increased to allow at least 10 working days which would be at least 15 calendar day increments. VSL for R2, part 2.1 - The 10 day increments represent a 1% error and considering this is a 24 month requirement. Recommend the increments be increased to 30 days to make more sense with the 24 month period.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Pacific Gas and Electric Company	No	do not line up with probability and potential severity
Response: Thank you for your comment. **The drafting team assigned the VRFs in accordance with the NERC criteria and FERC guidelines for establishing VRFs, and believes the assigned risk factors are appropriate.**		
Flathead Electric Cooperative, Inc.	No	Comments: We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in "guidelines and Technical Basis" that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
ReliabilityFirst	No	ReliabiltiyFirst beleives the VRF for Requirement R4 should be High since it requires completion of the coordination activities. Lack of coordination of Protection Systems can result in larger scale outages.
Response: Thank you for your comment. **The drafting team disagrees and believes the VRF for Requirement R4 more aligns with the NERC criteria for a medium risk.**		
LCRA Transmission Services Corporation	No	Objectives of R2 and R4 are mostly associated with interchange of information and the associated Violation Risk Factor for these two requirements (R2 and R4) should be LOW.
Response: Thank you for your comment. **The drafting team respectfully disagrees and believes the VRFs for Requirements R2 and R4 align with the NERC criteria as established. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner, and reaching agreement on Protection System settings and schemes. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur.**		
Ameren	No	We recommend to the SDT that a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale this

Organization	Yes or No	Question 8 Comment
		urgency is not warranted. Most entities will have numerous Interconnection Facilities so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: (a) Lower VSL should be 30 days late. (b) Moderate VSL should be more than 30 days, less than a year. (c) High VSL should be more than a year but done. (d) Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Portland General Electric Company	No	No, Severe VSL for lateness should only apply to R4.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs and believes the assigned VSLs are appropriate.**		
American Transmission Company	No	The VSLs, in general, are much more severe than the risk to the BES and should be rewritten to more accurately reflect the risk. For example: if a BES Element is replaced "like for like" with no material impact to the associated settings and a failure to notify by more than 30 days occurs, the issue is assigned a Severe VSL yet there

Organization	Yes or No	Question 8 Comment
		was no effective change to BES reliability.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. Note, in your example, if it is an exact "like for like" replacement with no setting changes – no notification would be required as this would not be covered by the standard; however, any replacement with a different style and/or changes of settings would be applicable under this standard and require notification.**		
NPPD	No	The time lines monitored down to 10, 20 or 30 days appear to be impractical in terms of monitoring for facility owners and in terms of auditing by compliance entities. This diverts the focus or sharing the data in a timely manner prior to project in service dates.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Trans Bay Cable	No	Comments: We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in "guidelines and Technical Basis" that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.
Response: Thank you for your comment.		

Organization	Yes or No	Question 8 Comment
The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.		
Duke Energy	No	The requirements in this standard do not have solely one activity. Also, requirements R1, R2, and R4 do not have an activity or goal stated (other than is stated in the subparts). The requirements in this standard all have sub-requirements, multiple measures and VSLs consisting of various combinations of non-compliance with sub-requirements. We think the standard could be made clearer by separating sub-requirements out as separate requirements with their own measure and VSLs.
Response: Thank you for your comment. **The drafting team considered your suggestion and declines to make the suggested changes to the standard content.**		
Oncor Electric Delivery Company LLC	No	Until 'agreement' definitions or further clarity as to what is an "agreement", can be added the Standard, Oncor does not believe that VRFs and VSLs can be established for this standard.
Response: Thank you for your comment.		
ExxonMobil Research & Engineering	No	
Liberty Electric Power LLC	No	
Dominion	No	Dominion recommends a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale this urgency is not

Organization	Yes or No	Question 8 Comment
		warranted. Most entities will have numerous Interconnection Facilities so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: • Lower VSL should be 30 days late. • Moderate VSL should be more than 30 days, less than a year. • High VSL should be more than a year but done. • Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Independent Electricity System Operator	Yes	We generally agree with the VRFs and the VSLs for the requirements as presented, but we have concerns with some of the requirements and hence reserve our comments until we see revisions made to these requirements.
Response: Thank you for your comment and support.		
Texas Reliability Entity	Yes	In the Severe VSL for R4.3, the word "entity" was left out after "The responsible . . ."
Response: Thank you for your comment. The error was corrected.		
Georgia Transmission Corporation	Yes	Meets NERC time frame practice.
Response: Thank you for your comment and support.		

Organization	Yes or No	Question 8 Comment
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
National Grid USA / Niagara Mohawk	Yes	
Hydro One	Yes	
Imperial Irrigation District (IID)	Yes	
Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
ISO RTO Council SRC	Yes	
Operational Compliance	Yes	
Idaho Power Company	Yes	
City of Austin dba Austin Energy	Yes	
Manitoba Hydro	Yes	
Exelon	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 8 Comment
Tri-State G & T	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
MWDSC	Yes	
ATCO Electric	Yes	
Clark Public Utilities	Yes	
South Carolina Electric and Gas	Yes	
Pepco Holdings Inc. & Affiliates		No Comments
FirstEnergy		No answer or comment at this time.
Public Service Enterprise Group		Did not evaluate.
mason		No comment

9. If you have any other comments that you have NOT provided in response to the above questions, please provide them here. (Please do not repeat comments that you provided elsewhere.)

Summary Consideration:

Some commenters wanted the drafting team to further modify PRC-001-2 by adding a Measure for Requirement R1 or retire the standard. This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "The drafting team recommends 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".

Some commenters requested the time frame in Requirement 2, Part 2.1 be increased up to 60 months to coincide with studies associated with TPL-001-2 draft 5 Requirement R2, Part 2.6.1. The drafting team responded with the following: "The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require."

Numerous commenters wanted further clarification as to the definition of a Protection System Study and also what is included in a summary result. Other commenters did not want the term Protection System Study added to the NERC Glossary of Terms. The drafting team declined to modify the definition of the Protection System Study but did add the following to the description in the "Guidelines and Technical Basis": "System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions." The drafting team believes that the full description in the Guidelines and Technical Basis is now adequate and appropriate. The drafting team did add language to the standard to specify that the term Protection System Study will not be added to the NERC Glossary of Terms. "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 Glossary of Terms:"

Some commenters expressed concern over the number of time frames associated with the coordination process and the burden of documentation. The drafting team believes the assigned time frames and documentation are appropriate and necessary and declined to make any changes.

Numerous commenters wanted the description associated with Figure 3 clarified. The drafting team noted that: Figure 3 is independent of whether the facilities are part of the BES. The intent is to identify that the coordination is required where Protection Systems are installed for the purpose of protecting Transmission System Elements. The drafting team added a note of clarification of the phrase

"Protection Systems installed to detect faults on the BES Transmission System." Figure 3 represents a generator connected to a Distribution Provider. The drafting team revised the description relating to Figure 3 in the "Guidelines and Technical Basis" to clarify that only the Distribution Provider's Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard. The drafting team modified Figure 3 to indicate that the source could be a generator or a network system.

A few commenters suggested the Figures in the Application Guidelines needed clarification on what the Interconnected Facilities were in the Figures. The drafting team modified the text associated with each Figure to identify the Interconnected Elements.

Some commenters expressed concern over the need to provide evidence demonstrating that the information was received by the other entity. The drafting team modified Measures M6, M7 and M8 to indicate the evidence needed is dated documentation that the information was provided during the specified time frames.

Several commenters suggested changes to the process flow chart and the drafting team modified the flow chart to be consistent with the requirements.

A few commenters wanted time frames to be established for Requirement R1, Part 1.1.3. The drafting team reiterated that there in not a single time frame that would be appropriate for every project and chose not to modify the standard.

Several commenters wanted Requirement R4 to be revised because of compliance and agreement concerns. The drafting team revised the requirement for clarity.

Several commenters requested the Applicability Section 4.2 Facilities be modified to clarify the role of Distribution Providers. The drafting team responded that they believe the Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements should be included in the Applicability of this standard because those Protection Systems must be coordinated with the Protection Systems of other Facility owners.

A commenter requested clarification of the Fault current contribution specified in Requirement R2, Part 2. The drafting team modified Requirement R2, Part 2.2 to read "for the interconnecting bus(s) under consideration."

A commenter expressed concern that Requirement R2 mandated that an entity perform a short circuit study even if no Protection System Study existed. The drafting team modified Requirement R2, Part 2.1 to read: “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.”

Several commenters suggested various changes be made to the Purpose statement of the standard. Based on these comments, the drafting team modified the Purpose to read: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.” and also modified Requirement R1, Part 1.1 to reflect the change in the Purpose. It now reads: “Perform a Protection System Study for each Interconnected Element to coordinate Protection Systems, such that the least number of power system Elements are isolated to clear Faults as follows:”

Organization	Yes or No	Question 9 Comment
ACES Power Marketing Standards Collaborators		(1) Please restate section 4.2. It states that it applies to Protection Systems installed at Interconnected Facilities. “Installed at” is not really the intention. It should be Protection Systems installed to protect Interconnected Facilities. While they most likely would be at the Facility, they do not have to be. For example, a 500 kV transmission line is a Facility. Protection Systems will not be “Installed at” the line but rather at the substations. (2) If PRC-001-3 R1 is going to be retained, it needs to be further refined. a) First, it inappropriately uses the term area when referring to a GOP. While the BA and TOP do have Balancing Authority Areas and Transmission Operator Areas, no equivalent exists with the GOP. The GOP simply operates generating units not areas. b) Second, the requirement confuses the role of the GO and GOP. In the functional model, it is the GO that is responsible for installing, setting and coordinating generation protection systems not the GOP. Thus, it is not clear what role the drafting team envisions for the GOP being familiar” with the purpose and limitation of protection system schemes applied in its area”. c) Third, the requirement is written too broadly for the BA. Because the requirement compels the BA to be familiar “with the purpose and limitation

Organization	Yes or No	Question 9 Comment
		of protection system schemes applied in its area" this could literally require the BA to understand many protection schemes for which it has no direct or even indirect responsibility. For instance, distance and differential protection schemes are contained within the metered boundaries of a BA Area. This requirement would compel the BA to be familiar with them even though this knowledge would have zero impact on its decision making or responsibilities. This does not align with the responsibilities assigned to the BA in the functional model. The BA being included in this requirement is likely a vestige of the version 0 standards and should be corrected. When version 0 standards were translated from the policies, BA and TOP were simply substituted for control area regardless of the role the control area was playing in the requirement. (3) The NERC function model defines one role of the Transmission Planner as "define system protection and control needs". Should the Transmission Planner have a role in this standard? For instance, should the TP actually perform the short circuit studies? (4) The application guidelines and examples are very helpful in understanding the intent of the drafting team. However, we recommend revising the example regarding Figure 3. It would appear to assume a distribution level generator is part of the BES and subject to NERC standards. While it is possible for a generator on the distribution system to be part of the BES (i.e. if it is a Blackstart Resource), inclusion of such a generator would be unusual and an exception to the normal BES 100 kV threshold. If the generator is not part of the BES, there would be no Generation Owner registered to perform the coordination. Industry is likely to be sensitive to such an example. Removing the generator will still allow the example to communicate that a breaker and associated Protection System on the high side (100 kV or higher) of a distribution or step-down transformer would still have to be coordinated.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”
2. This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, “The drafting team recommends 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”.
3. Although the Transmission Planner may “define system protection and control needs”, it will be the owner that is responsible for determining the implementation and coordination.
4. Figure 3 is independent of whether the facilities are part of the BES. The intent is to identify that the coordination is required where Protection Systems are installed for the purpose of protecting Transmission System Elements.</td></tr>
<tr><td>Ameren</td><td></td><td>(1) We support and agree with the SERC Protection & Control Subcommittee comments.
(2) We commend the SDT on their high quality initial draft of PRC-027-1.
(3) We recommend that the SDT delete ‘operating’ from the Interconnected Facilities definition because their different functional or corporate entities sufficiently capture all of them. We also suggest defining the singular Interconnection Facility, rather than the plural.
(4) The SDT needs to improve the application guidance examples by stating what constitutes the Interconnection Facility. The first example clearly enumerates the short circuit locations and values to be compared between the most recent Protection Study and the R2 2.1 value.
(5) Application Guidelines Example / Figure 3: The Note should be clarified, or the example should be removed. In terms of regulatory requirements, Breaker-A and B should coordinate with Breaker-C. However, Breaker-C and the Generator relaying does not need to coordinate with Breakers at Station-1 or Station-2 unless the</td></tr>
</table>

Organization	Yes or No	Question 9 Comment
		generator meets the requirements of a BES element (75MW or greater). For small generators, protection on the generator to detect faults on the transmission system is for generation protection, not BES protection; as the fault currents would be too small to cause damage to the Transmission System. Generator protection is already covered in Example / Figure #2. (6) Please restate Effective Date more clearly, we suggest “PRC-027-1 shall become effective on the first day of the first calendar quarter [delete-that is] three months following [delete-beyond the date that this standard is approved by] applicable regulatory approvals [delete-authorities],...” to be consistent with the wording of other standards (e.g. PRC-005-2.) (7) Since short circuit data base models are required to perform the Protection System Study, NERC regions should have a consistent schedule for revising models. Please encourage regions to synchronize their regional modeling calendars to enable entities to have consistent models, especially near region borders, for efficient execution of PRC-027-1 (8) we recommend that the SDT add proposed NERC Standard TPL-001-2 to your list on page 5 regarding the Other Aspects of coordination. It requires short circuit studies in R2.8 for the purpose of determining if the short circuit interrupting requirements are within the interrupting capabilities of circuit breakers. (9) We strongly recommend that the SDT use the term ‘change’ rather than ‘deviation’ throughout for consistency and because the latter term is defined as being different from the norm. The new fault current value is now the norm, not abnormal or statistically different. R1 - 1.1.2 and 1.1.3 use ‘change’, but ‘deviation’ is then used about a dozen times thereafter in the document. (10) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process.

Organization	Yes or No	Question 9 Comment
		(a) The overall process would be less burdensome by changing the R2 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3.(b) The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. (b) Omitting ‘project schedule’ from R3 would streamline data exchange. (c) R3-3.1 and 3.3.1 should only be required IF the changes effect the tripping or coordinated functions. Digital relays include numerous settings besides these functions; and these other settings should not trigger a data exchange or study. (d) Streamline the process by measuring dates an entity sends information and receives final agreement. It is burdensome for the sending entity to also track and retain evidence showing another entity received information. Specifically change M2, M5, M6, M7, and M8 to measure the date sent. The other entity’s agreement in M9 shows that the overall process met overall time requirements and that the entities coordinated. If an entity demonstrates such a study is not required in R1, M1 should require the other entity to agree. (e) The application guidelines are generally clear and certainly clarify responsibility. We recommend somehow including their methodology in the requirements because it streamlines the exchanged data and clarifies the process in this complex and potentially voluminous undertaking.

Response: Thank you for your comment.

1. **See the response to the SERC Protection & Control Subcommittee comments.**
2. **Thank you for your support.**
3. **Based on comments, the drafting team modified Interconnected Facilities to Interconnected Elements defined as follows,**

Organization	Yes or No	Question 9 Comment

Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.

4. The drafting team has modified the figures to clarify what is the Interconnected Element.
5. Figure 3 is independent of whether the facilities are part of the BES. The intent is to identify that the coordination is required where Protection Systems are installed for the purpose of protecting transmission system elements. The drafting team has modified Figure #3.
6. The language for the Effective Date is the authorized text approved by NERC legal staff.
7. This is outside the scope of the drafting team.
8. The drafting team believes that the referenced requirement in TPL-001-2 is related to interrupting capabilities and is not directly related to Protection System coordination.
9. The drafting team believes that the term “deviation” is properly used in R2 Part 2.2 and is synonymous with the term “change”.
10. (a) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.

    (b) The drafting team believes that omitting the “project schedule” from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary.

    (c) Requirement R3, Part 3.1 states that the information shall be provided “when the proposed change modifies the conditions used in the coordination of Protection Systems…” The drafting team modified Requirement R3, Part 3.3 to eliminate Parts 3.3.1 and 3.3.2, but believes any information previously provided to another entity to ensure Protection System coordination must be provided if any of the information is changed pursuant to Part 3.3.

    (d) The drafting team believes that confirmation of receipt is an important aspect of information exchange and declines to

Organization	Yes or No	Question 9 Comment
make the suggested change. **(e) The drafting team believes that the "Guidelines and Technical Basis" is the appropriate place to elaborate on the responsibilities under the standard rather than including the information in the Requirements.**		
TransAlta Centralia Generation LLC		1) Applicability 4.2 Facilities should be Protection System installed at Interconnected Facilities that required coordination. 2) R2- For the Inteconnected Faculties only for the purpose of the generator interconnection, only the Transmission Owner providing the generator interconnection should be required to perform the tasks as mentioned in R2, not the other entity (generator) even though it is registered as the Transmission Owner. 3) R2 2.1 performs a short circuit study to determine the present fault current values, not less than once every 24 months. 24 months is too often. Suggest to change to "once every 60 months unless there is major equipment change on the system".
Response: Thank you for your comment. **1. Based on comments, the drafting team has changed the Application, 4.2 Facilities to "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements."** **2. The drafting team added the following to the Rationale for R2, "(This requirement does not apply to the subject Generator Owner if it is also registered as a Transmission Owner, unless also registered as a Transmission Owner interconnecting to its own generator)" to address your comment.** **3. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2.**		
Xcel Energy		1) It appears that clarification is needed in the Application guidelines with respect to the Generator Owners, Distribution Providers and Transmission Owners. If they are the same corporate entity, do the examples indicate as such and would coordination be required as specified? (It is presumed YES but not clear...e.g. GO

Organization	Yes or No	Question 9 Comment
		"R" and TO "S" could be the same corporate entity). Figure 5 implies the letters "R", "S", and "T" refers to different corporate entities since there is a Transmission Owner R and a Transmission Owner S along with a Generator Owner T. If these letters do not indicate different corporate entities, then is it the intention of the SDT that all GO and DP facilities that connect directly to the BES be treated as "Interconnected Facilities"?. 2) Additional clarification in the Application Guide (figure 3) is required as it would imply that proof is require that generation on a tapped substation does not pose a risk to the transmission system. 3) The dates and documentation requirements for this standard will require an equivalently complex system or database for tracking in order to prove compliance. From review of the standard it appears that tracking of ~8 dates and associated supporting documents will be required for each interconnection study. Additional implementation time should be included in the standard for proper processes and tools to be in place prior to perform study or re-study work. 4) Most study work would be initiated by R3.2 and typically involve multiple data requests for varying items and with associated responses providing the information. If each email request needs a corresponding response, then much time will be required to match emails topic for topic to meet this measure. The result will be multiple of same measure for study work, increasing tracking time for engineering. (i.e. more tracking time and less engineering time per engineering FTE). If the measure is to be based on first request to last response then this would easier to implement. 5) As existing studies will fall under the measures of this document, with no grandfathering, it is likely existing studies will need to be re-evaluated. As a result, consulting services for competent protection engineering services may become limited and may impact the ability in meeting the 36 month requirement. 6) Larger regional studies with interconnection impacts may be the outcome of

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<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td></td><td></td><td>more localized studies. Such studies could be recommended as a result of R2 of this document or future year models under R3.1. The time-frames specified in this standard may not be sufficient and no exception method is provided for expanded study work. (i.e.-studies beyond what is would be considered typical for an interconnection study).</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team has removed the term Interconnected Facilities and replaced it with Interconnected Elements, which is defined as “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.” The drafting team believes that the definition includes a Generation Owner and Transmission Owner that are part of the same registration, but would exclude a single Transmission Owner that is responsible for all interconnected terminals.
2. Based on comments received, the drafting team has revised the description relating to Figure 3 in the “Guidelines and Technical Basis”.
3. The drafting team believes that the proposed requirement time frames and effective date allow sufficient time to comply with the standard.
4. The drafting team did not change the standard based on this comment.
5. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists”
6. Based on comments, the drafting team has modified requirement 4, Part 4.2 to state, “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element agree with any resulting Protection System(s) changes.” The drafting team believes that regional studies as a result of Requirement 2 are outside the scope of this standard.</td></tr>
<tr><td>Pepco Holdings Inc. & Affiliates</td><td></td><td>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,</td></tr>
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Organization	Yes or No	Question 9 Comment
		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 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.

Organization	Yes or No	Question 9 Comment
		As such, although we support the overall desire to ensure that protective systems are “properly coordinated”; we see 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. 2) PRC-001 With the vast majority of the requirements from PRC-001-1 being removed, the Title and Purpose of proposed standard PRC-001-3 no longer seem appropriate for the content remaining therein and should be revised. The only remaining requirement in PRC-001-3 states that “Each Transmission Owner, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. This does not seem to be a Protection System Coordination issue. 3) The definition of Interconnected Facilities should reference Registered Entities rather than functional, operating, or corporate entities. BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities Registered Entities (TOs, GOs, and/or DPs). 4) Is Facility and/or Element the best term(s) to use in the definition? It seems to say Elements that are joined by Elements? If not, should the definition be further revised. NERC Glossary of terms for 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. NERC Glossary of terms for Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.) 5) Does joint own lines and stations create issues? Should the definition or standard

Organization	Yes or No	Question 9 Comment
		make a distinction between principal owner and financial owners?
Response: Thank you for your comment. **1. PRC-027-1 is replacing Requirements R2 and R3 of PRC-001-2. The drafting team is developing this standard based on the Standards Committee approved SAR, and is addressing directives issued by FERC in Order 693.** **2. This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff.** **3. The drafting team has removed the term “Interconnected Facilities” and replaced it with “Interconnected Elements,” which is defined as “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.”** **4. The drafting team replaced the term “Interconnected Facilities” with “Interconnected Element.”** **5. The drafting team believes that the individual owners’ Protection Systems are well defined, but if there is joint ownership in the Protection Systems, compliance responsibility has been delegated for other standards and this standard has a similar need for delegation of responsibility.**		
Northeast Power Coordinating Council		1. Referring to the Example Process on page 22, it should not be the responsibility of Entity B to propose revisions. It should be the responsibility of the Entity in the better position to propose a revision to propose the revision. There needs to be flexibility as to who is obliged to come up with a revision. 2. Regarding Fig. 2 and Fig. 5 in the Application Guidelines, it is important that the expertise of each entity involved in an interconnection be used to ensure that there are no coordination issues. For example, Generator Owners and Transmission Owners. 3. Application Guidelines Fig. 3 requires the TO to verify that the DP's and the GO's protection systems coordinate with the TO's, even though the GO doesn’t connect directly to the TO. It should be the DP that checks coordination of the GO with the DP for faults on the transmission side of the DP's substation transformer, and the TO that checks coordination of the DP's transmission protection with the TO. If all of the transmission protection is back at the GO (in other words the DP has installed no

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<tr><td></td><td></td><td>transmission protection at its sub) then to do as this app guide suggests the TO will require an accurate short circuit model of the DP's system between the GO and the TO. It would require that the DP keep the TO continuously appraised of changes to the DP's system that impact the short circuit representation. Considering the proliferation of distributed generation being interconnected to distribution systems the burden should be on the DP not on the TO supplying the DP to verify coordination. The scope of the text "....generator protection systems...." should be narrowed so a TO or DP is not responsible for the coordination of devices it doesn’t own, maintain or set.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team believes that the Example Process does allow the flexibility that you describe. The collaboration would begin at the point where Entity B responds to Entity A with its proposal.
2. The drafting team believes that there is flexibility in the process to allow for the expertise of each entity to be used to coordinate Protection Systems.
3. Based on comments received, the drafting team has revised the description relating to Figure 3 in the “Guidelines and Technical Basis” to clarify that only the Distribution Provider’s Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard.</td></tr>
<tr><td>Independent Electricity System Operator</td><td></td><td>1. As a general comment, we do not support defining new terms which have limited applications (e.g. for use in one or very few standard) and which are short and therefore can be equally effectively expressed in the requirement that the term or its intended meaning is used. Adding new terms to the NERC Glossary when not absolutely necessary creates unnecessary maintenance workload and dependency among standards that use the same term, making it far more difficult to revise a standard without addressing the ripple effects. While we do not oppose to defining the term Interconnected Facilities as it serves to clarify and provide the boundary of the Facility, and we see its potential application to other standards, we disagree with defining the term “Protection System Study”. The definition contains an objective “operate in the</td></tr>
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Organization	Yes or No	Question 9 Comment
		desired sequence for clearing Faults" that should be stipulated in the standard requirements themselves. Further, as suggested below, the requirements that this term is used can be easily revised to convey the meaning of the definition: R1, 1.1 Perform a study for each Interconnected Facility to verify that Protection Systems operate in the desired sequence for clearing Faults and remove from service only those Elements required to isolate Faults as follows:1.1.1 Within 36 calendar months after the effective date of this standard, if no such study for that Interconnected Facility exists that was performed on or subsequent to June 18, 2007R1, 1.2 Provide to each affected Interconnected Facility owner a summary of the results of each study performed pursuant to Part 1.1 of this requirement, (including, at a minimum, the Protection System(s) reviewed, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each study.R2, 2.2 Calculate the percent deviation between the Fault current values (single line to ground and 3-phase for the bus(s) or Element(s) under consideration) used in the most recent study performed under Part 1.1 of R1 and the Fault current values....Vpss = Fault current value used in the most recent studyR4, 4.1 Within 90 calendar days after receipt, confirm agreement with the summary results of a study as described in Requirement R1, Part 1.2.Conforming changes can be made to the associated Measures and VSLs. 2. 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. If this is a training requirement, it should be transferred to the appropriate PER standards. c. Measures M1 is removed from the standard. This does not conform with the Elements of a Reliability Standard template, specifically those specified in the

Organization	Yes or No	Question 9 Comment
		"Mandatory and Enforceable Sections of a Standard". d. 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. However, leaving this not measurable and unnecessary requirement in PRC-001-3 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 could have proposed 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. 3. The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after "where such explicit approval is required" in the Effective Dates Section on P. 2, to the following effect:", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."

Response: Thank you for your comment.

1. **The drafting team believes that defining the term "Protection System Study" is the most efficient way to refer to the necessary reviews and the best way to allow for description of the studies.**
2. **This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff.**
3. **The drafting team believes that the "Effective Dates" language used in the standard and in the Implementation Plan is appropriate and consistent with other reliability standards.**

Organization	Yes or No	Question 9 Comment
Southern Company		1. The separation of PRC-001-1 in three directions is appreciated. This move was a move in the right direction in our opinion. 2. Whereas the SPCTF may believe that the existing PRC-001-1 was too vague and was not measureable, we believe that the initial draft of PRC-027-1 is overly specificative. Contained within the four listed requirements are actually 11 requirements with 11 different time critical counters that are not to be violated. It is our opinion that equally effective reliability improvement results can be achieved with a standard that is of the form of something in between these two extremes. We propose to eliminate the multiple calendar based time framed requirements and simplify the eleven requirements into four simply stated requirements. The four requirements, simply, could be: 1) For each Interconnect Facility (IF), perform a Protection System coordination study/review every X years or sooner if triggered by Y. (Y = available fault current change % [r-iii below], system configuration change or other protection system change [r-ii below]); 2) IF owners must notify other IF owners of changes that may affect the other IF owner's Protection System coordination study. (list items likely to affect coordination-this list includes everything in the draft standard R3); 3) TOs are to notify other IF owners if available fault current changes significantly %; 4) IF owners must share & acknowledge receipt and review of their IF Protection System coordination study with other IF owners of that IF. 3. On figure 5 (p. 27 of the draft standard), it seems unreasonable to require that the GO coordinate their protection with that associated for breakers E, F, and G, which are three breakers away from the generator.

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<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td></td><td></td><td>4. There is an error on p 5 of the Technical Justification document under Requirement R3. In the first sentence, it is R1, not R3, that requires the IF owners to evaluate the impact to their Protection Systems due to proposed changes by others.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team thanks you for your support.
2. The drafting team understands your concerns but believes that the requirements and associated time frames are the best way to ensure that Protection System coordination is achieved in a non-discriminatory fashion.
3. The drafting team believes that the Generator Owner may have overreaching elements that require coordination with breakers E, F, and G and thus made no changes to the standard based on this comment.
4. Based on your comment the drafting team modified the sentence to “This requires the registered functional entity initiating any change to provide the details to the other affected entities of the Interconnected Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes.”</td></tr>
<tr><td>Hydro One</td><td></td><td>1. This standard has been written on the basis that one of the Entities initiates the process and that both, assuming 2 only, conduct their own independent Protection System Studies; and then at the end of the process they agree, etc. Based on our experience, it is more efficient that both parties work in cooperation to conduct the Protection System Study and that they produce one report document which is then approved by both entities as meeting adequate coordination requirements. The Protection System Studies report shall be dated, and include the fault values at the time of assessment and should be filed as compliance evidence.
2. The SDT states “The SDT has no evidence there is widespread miscoordination between Interconnected Facilities....” This is contrary to the NERC TRD that indicated that there were plenty of co-ordination issues during the 2003 Blackout. Suggest removing this statement as it is contradictory and serves no purpose since the documented Protection System study has to take place regardless.
3. We feel the standard would be more useful to the industry if a list of applicable</td></tr>
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Organization	Yes or No	Question 9 Comment
		Protection System elements that require co-ordination is presented in the requirements section in line with the NERC white paper. Much like PRC-023 that identifies specific elements and corresponding numbers, we feel this approach would result in proper Protection System studies being undertaken for elements that are affected by this standard. The SDT claims some elements will be covered in other standards so the scope of elements that need co-ordination needs some clarity. 4. PRC-001-3 lists “first day of the first calendar quarter twelve months following” as the Effective Date. However, the implementation plan states that the effective date is the same as for PRC-027-1 which is “first day of the first calendar quarter that is three months beyond”. Please clarify and ensure consistency. 5. Hydro One is questioning the purpose and existence of PRC-001-3 in its current form. It contains only one requirement that is very vague and not measurable. Suggest that the SDT retires that standard as a part of this project 6. To avoid confusion we ask the SDT to establish 1 to 1 correspondence between the requirements and measure. For example R2 measures should be M2 or M2.1, M2.2 rather than M3 and M4.

Response: Thank you for your comment.

1. **The drafting believes that the standard does not preclude collaboration between the affected entities when performing the Protection System Study.**
2. **The drafting team believes that the coordination issues addressed in the 2003 Blackout report were related to UFLS, UVLS, and generator controls. While there were statements of general philosophy about the need for coordination of transmission line protection, there were no examples of miscoordination. As such, the drafting team has declined to remove the suggested statement from the standard.**
3. **Based on comments, the drafting team modified the Facility Applicability 4.2 to “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements,” which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard.**
4. **The drafting team has modified the effective dates so they will be consistent. The effective date for PRC-001-3 is now**

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<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td colspan="3">described as “This standard becomes effective coincidently with PRC-027-1.”
5. The retirement of PRC-001-3 is beyond the scope of this drafting team; however, your comment will be forwarded to NERC staff.
6. The drafting team followed the format outlined in the NERC “Standard Processes Manual,” effective January 31, 2012.</td></tr>
<tr><td>National Grid USA / Niagara Mohawk</td><td></td><td>1. Regarding the definition of “Interconnected Facilities,” when the functional and operating entities are part of the same corporate entity documented correspondence within that same corporate entity seems of little benefit. In fact, it could be the same individual wearing two hats in the same corporate entity who would have to document communications with him/herself.
2. Example process on page 22 should not automatically make it the responsibility of entity B to propose a solution to a problem discovered by entity A quite possibly resulting from system modifications initiated by entity A. Whether entity A or entity B is in a better position to propose a solution depends entirely on the circumstance and there needs to be flexibility as to who is obliged to come up with a fix.
3. Application Guidelines, Fig. 2 and Fig. 5 require the TO to verify "...the generator Protection Systems..." coordinate with the TO's systems. The scope of generator protection systems should be narrowed to just distance relays and overcurrent relays that look out onto the TO's system. If the high side winding of the transformer that interconnects to the TO is ungrounded and zero sequence overvoltage protection is provided for the transmission, then that would be appropriate to include in the scope of TO responsibilities too. The expertise in other types of generator protection likely resides with the GO and not the TO so it would be best if the GO handled the coordination of those other types of protection.
4. Application Guidelines, Fig. 3 requires the TO to verify the DP's and the GO's protection systems coordinate with the TO's. Yet the GO doesn’t even connect directly to the TO. It should be the DO that checks coordination of the GO with</td></tr>
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Organization	Yes or No	Question 9 Comment
		the DP for faults on the transmission side of the DP's substation transformer (assuming the DP has installed transmission protection at the sub) and the TO that checks coordination of the DP's transmission protection with the TO. If all of the transmission protection is back at the GO (in other words the DP has installed no transmission protection at its sub) then to do as this app guide suggests the TO will require an accurate short circuit model of the DP's system between the GO and the TO. Furthermore it would require that the DP keep the TO continuously appraised of changes to the DP's system that impact the short circuit representation. Considering the proliferation of distributed generation being interconnected to distribution systems the burden should be on the DP not on the TO supplying the DP to verify coordination of what could be a multitude of interconnections to the DP. Furthermore, the scope of the text "....generator protection systems...." should be narrowed so a TO or DP is not responsible for the coordination of devices it doesn't even own, maintain or set. When study work is required to interconnect a GO to an entity, the entity is commonly reimbursed by the GO for study work. Yet this app guide requires a TO to perform study work for the benefit of a GO which does not even directly interconnect with it so how will the TO be reimbursed for it's efforts?

Response: Thank you for your comment.

1. **The drafting team has removed the term Interconnected Facilities and replaced it with Interconnected Elements, which is defined as "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity." The drafting team believes that the definition includes a Generation Owner and Transmission Owner that are part of the same registration, but would exclude a single Transmission Owner that is responsible for all interconnected terminals.**
2. **The drafting team believes that the Example Process does allow the flexibility that you describe. The collaboration would begin at the point where Entity B responds to Entity A with its proposal.**
3. **The drafting team believes that there is flexibility in the process to allow for the expertise of each entity to be used to coordinate Protection Systems.**

Organization	Yes or No	Question 9 Comment
4. Based on comments received, the drafting team has revised the description relating to Figure 3 in the "Guidelines and Technical Basis" to clarify that only the Distribution Provider's Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard.		
Tennessee Valley Authority		a)Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1, Part 1.1.2 reads - "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required." For Requirement R1, Part 1.1.2, we recommend omitting the reference to R2 and reword so that the requirement is specific. Recommend changing to read: "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required". b) The standard uses different formats for identifying deadlines. Sometimes "days" are used and sometime "months" are used. It is suggested that a common format be used. c) Please note that there appears to be an inconsistency in the 24 month requirement of R 2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual Requirements where time schedules are involved, the wording of the Requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the

Organization	Yes or No	Question 9 Comment
		time schedule at the beginning of the Requirement whereas R1-1.2 references the time schedule at the end of the Requirement. Recommend using a standard wording format and list the time horizons in the beginning of the Requirement in all Requirements that have time requirements involved. For Requirement R1-1.2, we recommend changing to read: "Within 90 calendar days after the completion of the Protection System Study: Provide, to each affected Interconnected Facility owner, a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions)." e) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. i) The overall process would be less burdensome by changing R2, Part 2.1 to "not less than once every 5 calendar years" which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3. ii) The overall process would be less burdensome by deleting R3, Part 3.3 because such Protection System changes are already captured by R3, Parts 3.1 and 3.2. iii) Omitting 'project schedule' from R3 would streamline data exchange. f) Delete 'operating' from the Interconnected Facilities definition because "different functional or corporate entities" sufficiently captures all of them. We also suggest defining the singular Interconnection Facility, rather than the plural.

Response: Thank you for your comment.

a. **The drafting team believes that your proposal does not change the requirement and the reference to the other requirements in this standard is the best way to both maintain consistency and to describe the requirements. The team declined to make the suggested changes.**

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td colspan="3">b. The drafting team chose to use “months” for any measurable period longer than 90 calendar days and believes this does not introduce any problem with meeting the requirements.
c. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.
d. The drafting team believes that references to the time horizons are accurately and sufficiently described and declined to make the suggested changes.
e. i) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.
ii) Based on comments, the drafting team combined Requirement 3, Parts 3.3.1 and 3.3.2 into Part 3.3. However, the drafting team notes that the triggers for Requirement R3, Part 3.3 are different than those for Requirement R3, Parts 3.1 or 3.2 and therefore declines to delete Requirement R3, Part 3.3.
iii) The drafting team believes that omitting the “project schedule” from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary.
f. Based on comments, the drafting team changed Interconnected Facilities to Interconnected Elements defined as follows, Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.</td></tr>
<tr><td>SERC Protection and Control Subcommittee</td><td></td><td>a)Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another</td></tr>
</table>

Organization	Yes or No	Question 9 Comment
		Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1-1.1.2 reads - “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.” For Requirement R1-1.1.2, recommend omitting the reference to R2 and reword so that the requirement is specific. Recommend changing to read: “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required”. b) The standard uses different formats for identifying deadlines. Sometimes “days” are used and sometime “months” are used. It is suggested that a common format be used. c) Please note that there appears to be an inconsistency in the 24 month requirement of R2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1, which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual requirements where time schedules are involved, the wording of the requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the requirement whereas R1-1.2 references the time schedule at t the end of the requirement. Recommend using a standard wording format and list the time horizons in the beginning of the requirement in all requirements that have time requirements involved. For Requirement R1-1.2, recommend changing to read: “Within 90 calendar days after the completion of the Protection System Study, provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed (including at a

Organization	Yes or No	Question 9 Comment
		minimum the Protection System(s) reviewed and any proposed revisions).” e) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. i) The overall process would be less burdensome by changing the R2 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above).Our experience is that the vast majority of Protection System Studies are triggered by R3. ii) The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. iii) Omitting “project schedule” from R3 would streamline data exchange. f) Delete “operating” from the Interconnected Facilities definition because different functional or corporate entities sufficiently capture all of them. We also suggest defining the singular Interconnection Facility, rather than the plural.”The comments expressed herein represent a consensus of the views of the above named members of the 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.

a. **The drafting team believes the reference to the other requirements in this standard is the best way to both maintain consistency and to describe the requirements. The team declined to make the suggested changes.**

b. **The drafting team chose to use “months” for any measurable period longer than 90 calendar days and believes this does not introduce any problem with meeting the requirements.**

c. **The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually**

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td colspan="3">**(Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.**
d. The drafting team believes that references to the time horizons are accurately and sufficiently described and declined to make the suggested changes.
e. i) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.
ii) Based on comments, the drafting team combined Requirement 3, Parts 3.3.1 and 3.3.2 into Part 3.3. However, the drafting team notes that the triggers for Requirement R3, Part 3.3 are different than those for Requirement R3, Parts 3.1 or 3.2 and therefore declines to delete Requirement R3, Part 3.3.
iii) The drafting team believes that omitting the “project schedule” from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary.
f. Based on comments, the drafting team changed Interconnected Facilities to Interconnected Elements defined as follows, Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.</td></tr>
<tr><td>Operational Compliance</td><td></td><td>All of the questions in this survey should elicit a "yes" response to agree with the Standard. Question 2 elicited a "no" response even though we agree with the part of the standard in the question. The questions in this survey should be worded to ask if we agree with the exact wording of the standard. For example, in Question 4 the wording of the question is different than in the Standard regarding deviation.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment. The drafting team agrees.**</td></tr>
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Organization	Yes or No	Question 9 Comment
City of Austin dba Austin Energy		Austin Energy (AE) agrees with PRC-027-1 in concept and is prepared to change our vote to affirmative once the SDT addresses the items in these comments. In addition to those provided as part of the specific questions, AE provides the following comments for consideration: (1) AE requests the SDT to identify a timeframe for R1.1.3. The Guidelines and Technical Basis (p17 of PRC-027-1 Draft #1) states, "The SDT believes that specifying a single time frame for evaluation of the wide variety of conditions that may be associated with a particular change is not appropriate ..." The flowchart on page 21 shows a system change that triggers the need for a new study leading to a box that requires the study be performed within six months. Please remove the conflicting information. (2) AE supports a timeframe that requires a Protection System Study in accordance with a mutually agreed-upon schedule that includes confirmation of agreement with summary results (per R4.1) prior to the in-service date of any planned change. AE suggests the SDT identify this timeframe in R1.1.3 and delete R4.2. (3) AE requests that the SDT change the values in the % Deviation formula (R2.2) from VSCS and VPSS to ISCS and IPSS since V is typically used for voltage. AE also requests the SDT change the variable definitions from "fault current value ..." to "fault current magnitude ..." to clarify that the phase angle is not included.

Response: Thank you for your comment.

1. **The drafting team has modified the flowchart based on comments and to reflect all changes made to the standard.**
2. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**
3. **Based on comments, the drafting team has modified the equation to replace "V" with "I." The drafting team kept the phasor values of the current in the calculation but included the percent deviation to be the absolute value of the percentage change**

Organization	Yes or No	Question 9 Comment
in the current to remove the angle from the final result.		
Oncor Electric Delivery Company LLC		Based on a thorough review of the proposed Standard, Oncor has identified several questions or comments which need to be addressed in the Standard to ensure the Requirements are clear. 1. R4.1: please provide clarification of which entity would be out of compliance if the 90 day requirement is not met - initiating entity or receiving entity or both 2. M9: What does "confirmation" mean as explained in Measure M9? 3. R4: please incorporate a definition of “agreement” 4. R4.2: please incorporate some examples for "evidence of agreement"? 5. There are two types of agreement that are needed; the first being an "agreement" with the overall projected relaying scheme (i.e. agreement with preliminary conceptual design detailing proposed protection scheme changes). This is prior to any equipment being purchased. The second agreement, which could be identified as more of a concurrence, is agreement that both relay systems coordinate from a protection standpoint (i.e. concurrence with relay setting changes). The relay setting process and concurrences occur later in the project closer to the in-service dates. In addition, the sub requirements 4.3.1 and 4.3.2 calls for confirmation of the Protection System changes are acceptable pursuant to notification received in Requirement 3, within 30 days, however the sub requirements provide no mechanism for resolution in the event the changes are not acceptable to the receiving entity within 30 days of receipt. Oncor suggest that these two sub requirements be removed. There are sufficient checks and balances under 4.2 to provide coverage for any disagreement between entities without the need to self-report under the 4.3.1 and 4.3.2 if an agreement cannot be reached within 30 days of receipt.

Organization	Yes or No	Question 9 Comment
		6. R3.1: please provide further clarification of the statement "modifies the conditions used". It would seem that most system changes would modify the conditions used even though for many of those changes, coordination would not be impacted. Oncor takes the position that the phrase provides ambiguity and subjectivity that would difficult to measure or audit.

Response: Thank you for your comment.

1. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes..**
2. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Measure M9 was revised to read: "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."**
3. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Acceptable evidence for 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"**
4. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm that the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."Acceptable evidence for 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."**
5. **Based on comments, Requirement 4, Part 4.3 was removed.**
6. **Based on comments, the drafting team clarified the items in Requirement 3, Part 3.1 to indicate which items the drafting team**

Organization	Yes or No	Question 9 Comment
believes modify the conditions used in the coordination of Protection Systems.		
Luminant		Comment on Requirement R1.2. The time frame listed may not be adequate under all circumstances or situations. Luminant recommends that the language be changed in this requirement as follows: "... Protection System Study performed pursuant to this requirement (including at a minimum, the Protection System(s) reviewed, any issued identified, and any revisions proposed) shall be in accordance to an agreed-upon schedule with a Transmission Owner, Generation Owner, of Distribution Provider." The corresponding measures will also need to be modified if this language is accepted.
Response: Thank you for your comment. **The drafting team believes that 90 days is adequate time to provide the owner(s) of the Protection System(s) associated with the Interconnected Element(s) with the summary of the results of a Protection System Study and declined to change the standard based on this comment.**		
Trans Bay Cable		Comments: The comment group agrees with the WECC Position Paper that the standard as written requires excessive and burdensome documentation that is not needed to demonstrate coordination.
Response: Thank you for your comment. **The drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.**		
Dominion		a). Dominion is concerned that a YES vote will also endorse the revision, also part of this project, to PRC-001-3, would then be reduced to only one requirement that is not measurable and does not contribute to the purpose of the standard. The Measure for the requirement has also been removed. The PRC-001 standard should be retired or mapped to another standard.

Organization	Yes or No	Question 9 Comment
		b). The proposed definition of Protection System Study is vague and introduces subjective terms such as "demonstrates" and "desired sequences". Recommend the following definition: "<u>A study that determines the proper selection of settings for existing or proposed protective relays in order to properly isolate Elements."</u> c). Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1-1.1.2 reads - **"Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required."** For Requirement R1-1.1.2 - Omit the reference to R2 and reword so that the requirement is specific. Recommend changing to read: <u>"Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required"</u>. - Change R1-1.1.3 wording to read <u>"When proposing or being notified of a change that modifies the conditions used in the coordination of Protection Systems at the Interconnected Facility unless the entity can demonstrate such a study is not required."</u> - R2-2.2, delete reference to R2. Delete "pursuant to Requirement R2, 2.1". - Change R4-4.1 to read: <u>"Within 90 calendar days of receiving summary results of a new Protection System Study, confirm agreement with the summary results."</u> - Change R4-4.2 to read: <u>"Prior to the installation of a proposed change that</u>

Organization	Yes or No	Question 9 Comment
		modifies the existing conditions used in the coordination of Protection Systems of the Interconnected Facilities, confirm the affected Interconnected Facility owner(s) agree with the Protection System(s) change.” - Change R4-4.3.1 to read: “Changes made to a Protection System as a result of findings during Misoperation investigations, commissioning, or maintenance activities, confirm the Protection System(s) changes are acceptable.” - Change R4-4.3.2 to read: “Emergency replacements are made due to failures of Protection System components confirm the Protection System(s) changes are acceptable.” d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual Requirements where time schedules are involved, the wording of the Requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the Requirement whereas R1-1.2 references the time schedule at the end of the Requirement. Recommend using a standard wording format and list the time horizons in the beginning of the Requirement in all Requirements that have time requirements involved. For Requirement R1-1.2, Change wording to read: **“Within 90 calendar days after the completion of the Protection System Study, provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions).”** - Change R2- 2.3 wording to read: Within 30 calendar days after identifying that the calculation performed between the previous Protection System Study and the new study indicates a change in Fault current of 10% or greater, notify each Interconnected Facility owner, at which the 10% or greater change applies.

Organization	Yes or No	Question 9 Comment
		- Chang R3-3.2 wording to read: “Within 30 calendar days of receiving a request for information in the absence of an agreed-upon schedule or according to an agreed-upon schedule with a Transmission Owner, Generator Owner, or Distribution Provider.” e). Throughout this 1st draft of the standard, there are references that illustrate documentation requirements that are inconsistent. Recommend all be written as “(hard copy or electronic file formats)”. f). Please note that there appears to be an inconsistency in the 24 month requirement of R 2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. g). There are several requirements stipulated throughout the draft standard creating the concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. 1). The overall process would be less burdensome by changing the R2 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3. 2). The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. 3). Omitting ‘project schedule’ from R3 would streamline data exchange. h). There is confusion on the connections at the end of the flow chart. Please provide clarification.

Organization	Yes or No	Question 9 Comment

Response: Thank you for your comment.

a. **The retirement of PRC-001-3 is beyond the scope of this drafting team; however, your comment will be forwarded to NERC staff.**

b. **The drafting team declines to modify the definition of the Protection System Study but did add the following to the description in the "Guidelines and Technical Basis": "System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions." The drafting team believes that the full description in the Guidelines and Technical Basis is now adequate and appropriate.**

c. **The drafting team believes the reference to the other requirements in this standard is the best way to both maintain consistency and to describe the requirements. The team declined to make the suggested changes.**

d. **The drafting team believes that references to the time frames are sufficient and declined to make the suggested changes.**

e. **The drafting team does not agree that the references "illustrate documentation requirements that are inconsistent." Each measurement in the standard (M1 through M10) has as evidence the statement "dated documentation (hardcopy or electronic file formats)."**

f. **The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.**

g. **1) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard**

Organization	Yes or No	Question 9 Comment
does not require. **2) Requirement R3, Part 3.3 was not in the version of the standard that was sent out for comment. Based on consideration of comments the subparts (R3.31 & R3.3.2) have been combined as Requirement R3 Part 3.3.** **3) The drafting team believes that omitting the "project schedule" from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary.** **h. The drafting team has modified the flowchart based on comments and to reflect all changes made to the standard.**		
Idaho Power Company		1. During our review it appears that an Entity will need to maintain an exceedingly large list of contacts for all Interconnected Facilities in order to ensure that the appropriate personnel receive and respond appropriately to Protection System coordination requests as Required by this Standard. With the probability of regular turnover occurring (retirements, transfers, etc.) at Interconnected Facilities, it would be helpful for a master list of Interconnected Facility Contacts for Protection Systems be held by a centralized Entity, such as a Reliability Coordinator, in order for an Entity to meet the timeframes specified and facilitate reliability via compliance with this Standard. 2. This Standard will enforce consistent communication between Entities which is necessary for coordination of Protection Systems. It does not however, guide an Entity to set relays that will ensure proper coordination. Having a separate Entity verify coordination is desirable, but differences in experience, expertise, and analysis tools between Entities will not ensure proper coordination if methods of checking are not also part of the Requirements.
Response: Thank you for your comment. **1. Your comments concerning the need for a current listing of "Interconnected Facility Contacts" is very perceptive, but cannot be addressed by the Requirements of the standard. The drafting team believes that ultimately it is the owner's responsibility**		

Organization	Yes or No	Question 9 Comment
to maintain this list; however, if you can reach an agreement with the Reliability Coordinator, that may be option. **2. The drafting team agrees with your comment that the “Standard will enforce consistent communication between Entities which is necessary for coordination of Protection Systems” but disagrees with your assertion that “Entities will not ensure proper coordination if methods of checking are not also part of the requirements.” The drafting team believes that all interconnected Protection System Owners have the capability of self checking their setting that will ensure coordination without making external checking of Protection Studies a Requirement of this standard.**		
FirstEnergy		FE offers the following additional comments: a. PRC-001-2 R1 - This requirement is vague and causes difficulties in consistent interpretations between entities and auditors. We ask the drafting team to revise the wording to clarify the expectations, such as including the types of protections system limitations they should be aware of. Enhancements to this requirement were also suggested in the “NERC SPCTF Assessment of Standard PRC-001-0 - System Protection Coordination” which is attached to the SAR of this project. In their assessment of R1 of PRC-001, the SPCTF said “This requirement is a statement of a highly laudable goal, but this is not specific and enforceable. .. It may be possible to restate this requirement in such a way to be measurable and enforceable. The protective system equipment owners (Transmission Owners, Generator Owners, and Distribution Providers) should be responsible to provide the necessary information to the Transmission Operator and Generator Operator to facilitate their familiarity with the relevant protective systems.” We ask the SDT to review this assessment and make changes to PRC-001 and PRC-027 to assure the reliability goal of PRC-001 R1 is met. b. With the approval of PRC-027-1, Requirements R3 and R4 will be retired from PRC-001-1 (Requirements R2 & R3 from PRC-001-2, approved as part of the Real-time Operations Project 2007-03) PRC-001-3 will have the same effective date as PRC-027-1. However, in the redlined version of PRC-001-3, the effective date is designated as “the first day of the calendar quarter twelve months following applicable regulatory approval”. This is not what is specified in the

Organization	Yes or No	Question 9 Comment
		Implementation Plan.
Response: Thank you for your comment. a. **The drafting team believes that Requirement R1 falls outside the scope of Project 2007-06 and should 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.** b. **The drafting team has modified the effective dates so they will be consistent. The effective date for PRC-001-3 is now described as "This standard becomes effective coincidently with PRC-027-1."**		
LCRA Transmission Services Corporation		General Comment: First, as industry comments are considered by the SDT, the standard must continue to take into consideration that the fundamental objective of a protection system is to prevent equipment damage that may occur as a result of a short circuit by ensuring fault isolation. The secondary objective is to maintain the power delivery capability in the rest of the system during a fault. This must not be compromised. Second, setting of protective relays is an art and finding a balance between dependability and security is already a challenge and may be an area of disagreement amongst owners (in some cases entities may end up "agreeing to disagree"). The standard should not take away the protection system owner's responsibility and right to set its own protection systems by requiring "Approval" from other interconnection entities at the Interconnected Facility. Specific Comments: Title of the proposed standard- The title for this standard is misleading since it only applies to locations that contain Interconnected Facilities. LCRA TSC suggests changing the title to "Protection System Coordination for Interconnection Facilities" Terms-Protection System Coordination Study: A study that demonstrates existing or proposed Protection Systems maintain proper selectivity while clearing Faults.
Response: Thank you for your comment.		

Organization	Yes or No	Question 9 Comment
The drafting team agrees that two objectives of a Protection System are to “prevent equipment damage due to faults” and to “maintain the power delivery capability in the rest of the system during a fault.” **Based on comments concerning agreement, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”** **The drafting team does not believe the standard title is misleading and therefore did not adopt your recommended title.** **The drafting team does not agree with expanding Protection System Study to “Protection System Coordination Study. Also the drafting team does not agree that “maintain proper selectivity while clearing Faults” adds significant clarity to the current definition of a Protection System Study.**		
Western Area Power Administration		General: Western disagrees with NERC standards becoming too specific on technical issues such as protective relay coordination. Protection Engineers are highly skilled and trained in system coordination and should be left to determine the proper course of action without the hindrance of PRC-027-1 requirements. There is a reason why, historically, protection system coordination has been termed "the Art and Science of Protective Relaying." The proposed standard also mentions that "Protection Systems remove from service only those Elements required to isolate Faults..." This statement can be problematic since backup functions such as remote Zone 3 distance elements cannot be overlapped reliably yet are necessary for N-2 and beyond contingencies. Also, in some case it may be desirable to allow for intentional overlap or mis-coordination depending on the circumstances. These issues need to be resolved in the proposed standard or the standard eliminated. Specific issues: a. We have concerns over what NERC considers to be a "Protection System Study". Needs clearer definition. - Swap requirement positions R1 and R3. I.e. make R1 be R3 and R3 be R1.

Organization	Yes or No	Question 9 Comment
		b. R2.2: Provide equation. And, use “I” instead of “V” when referring to current. c. R2.2: What values are being referred to for deviation calculation? (i.e. ground current, phase current, positive sequence, etc.) d. R2.2: Clarify the fault current contribution or provide a table specifying the details e. R3.1: Last bullet, suggest making the statement “Replacement of the transformer(s)” to cover all transformers. f. R3.2: How does the neighboring entity know when to request? g. R3: What are the details to be provided? Should only be for significant changes. h. Concerned about dates and timelines associated with this standard. Often schedules and tasks change during design, checkout and commissioning. R1.1.3 and R3 need to be clarified. i. Western believes that this standard will create more questions than it answers. The standard, as written, is not clear or concise and would surely lead to CAN's and FAQ's.

Response: Thank you for your comment

a. **The drafting team believes that the definition of Protection System Study, “A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults” is understandable and succinct and does not need to be more clearly defined. Also the drafting team does not believe that Requirements R1 and R3 need to be swapped.**

b. **Per your suggestion and others, the drafting team has modified the equation to replace “V” with “I”.**

c. **The standard has been changed to refer to “Single line to ground and 3-phase for the interconnecting bus(s) under consideration” for the “deviation calculation.”**

d. **Based on comments the fault current contribution in Requirement R2, Part 2.2 has been clarified to be “for the interconnecting bus(s) under consideration.”**

Organization	Yes or No	Question 9 Comment
e. Other transformers are included in the second bullet which is now a combination of the previous version's second and third bullets. **f. In R3 Part 3.2 the "neighboring entity" can request information related to the coordination of Protection Systems of an Interconnected Element whenever it desires the information.** **g. The details to be provided for R3 Part R3.1, Part 3.2, and Part 3.3 of the standard are discussed in their respective parts and the Application Guidelines of the standard. However, the individual circumstance may dictate additional details that are required for a relay coordination study.** **h. The standard takes into account "schedules and tasks" changing "during design" by not establishing "dates and timelines" for Requirement R 3 Part 3.1. The drafting team believes that Requirement R3 and Requirement R1, Part 1.1. 3 have sufficient clarity in the respective standard Requirements and the Application Guidelines associated with the Requirements.** **i. The posting of the standard is intended to provide the opportunity for the drafting team to address industry comments and provide clarifications to the industry which will hopefully eliminate the need for CANs and FAQs.**		
Southern Minnesota Municipal Power Agency		I agree with and support the comments of the MRO's NERC Standards Review Forum (NSRF).
Response: Thank you for your comment. **Please see the response to MRO's NERC Standards Review Forum (NSRF)**		
Illinois Municipal Electric Agency		IMEA recommends language be included in 4.2 Facilities to clarify the standard does not apply to a DP protective device that only detects a fault on a transmission element and does not trip an interrupting device that interrupts current supplied directly from the BES. To minimize misinterpretation and potential impact on small entity resources, it would strengthen the standard if Section 4.2 Applicability language specifies the standard does not apply to a DP that does not own a BES Element/Facility.
Response: Thank you for your comment. **The drafting team believes Distribution Providers that own "Protection Systems installed for the purpose of detecting Faults on**		

Organization	Yes or No	Question 9 Comment
Interconnected Elements of the BES and that require coordination for isolating those faulted Elements" should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.		
American Transmission Company		1. In general, ATC agrees with the need to modify PRC-001. However, PRC-027 as written expands the scope of PRC-001 by including Distribution Providers (DP). 2. The SDT, on both page 6 and 16 states that there is "no evidence of widespread miscoordination between Interconnected Facilities..." They further state on page 16 that "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 Misoperation." Based on the above statements, ATC questions the need for the level of prescription in the standard. 3. ATC asks the SDT to update the numbering for measures to match the requirement numbering. 4. Reliability Standard TPL-001-2, which has been approved by NERC BOT, requires short circuit analysis. ATC believes that PRC-027-R2.1 is duplicative.
Response: Thank you for your comment. **1. The drafting team believes Distribution Providers that own Protection Systems installed for the primary function of detecting Faults on BES Elements should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners. To add clarity to this issue, the drafting team revised Applicability Section 4.2 Facilities as follows: Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements. Additionally, the drafting team changed the term "Interconnected Facilities" to Interconnected "Elements" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity"** **2. The drafting team stands by the quoted statement that there is "no evidence of widespread miscoordination between Interconnected Elements." However, because communication of changes at the interconnection or changes that effect the**		

Organization	Yes or No	Question 9 Comment
Protection Systems at an Interconnected Element is required for proper coordination, the “level of prescription in the standard” is required. **3. The drafting team followed the format outlined in the NERC “Standard Processes Manual,” effective January 31, 2012.** **4. The drafting team believes that the referenced requirement in TPL-001-2 is related to interrupting capabilities and is not directly related to Protection System coordination. The reliability intent and purpose of the two standards is different and therefore they are not "duplicative”.**		
Southwest Power Pool NERC Reliability Standards Development Team		1. In R2 the 24 month time period needs to be changed to 60 months. If fault currents are already being calculated for changes to the system there should be little to no need for a more current check of the fault currents. We feel like the 24 months could be burdensome to smaller entities. 2. We would ask that PRC-001-3 be retired and the requirement in it to be moved to a SAR for an existing PER training standard. It also seems incomplete that a standard with a single requirement has no measures. 3. Is there a need for the defined term “Protection System Study” in this standard to also be a new term in the NERC glossary of terms? Is there other wording that could be used in place of this new term since it is only being used as part of this standard?
Response: Thank you for your comment. **1. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2.** **2. This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, “The SPC SDT recommends 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”.** **3. The drafting team believes that the definition of Protection System Study is needed but based on your comment the drafting team has specified that the new term will not be added to the NERC glossary of terms.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td>Bonneville Power Administration</td><td></td><td>Interconnections are no more prone to misoperations than other power system elements. A logical conclusion is that if the requirements of this standard are put in place for interconnected facilities, they should be put in place for all power system elements. The industry is quickly approaching a prescriptive environment in the protective relaying field which attempts to replace experience and judgment with a massive set of rules. These rules will never be able to eliminate miscoordination and misoperations, and the more rules we have, the more time and resources are diverted from dealing with the critical issues that arise. Entities are no longer free to use experience and judgment to decide what work is most important and instead, focus time and energy on the relentless schedule of NERC requirements. The purpose of the original System Protection Coordination Standard, PRC-001, was to ensure that protection systems were coordinated among entities. This should require only a simple exchange of data between entities when new facilities are added or changes are made. BPA implores the SDT to reduce the burden of the proposed standard by simplifying it and returning to the basic original purpose.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team agrees that “Interconnections are no more prone to misoperations than other power system elements” and that the intent of the “original System Protection Coordination Standard, PRC-001, was to ensure that protection systems were coordinated among entities.” The Purpose of PRC-027-1 “To coordinate Protection Systems for Interconnected Elements ….” does not imply that the requirements of PRC-027-1, when put in place for interconnected elements, should be put in place for all power system elements. Because communication of changes at the interconnection or changes that effect the Protection Systems at an Interconnected Element is required for proper coordination, the level of prescription in PRC-027-1 is required. The drafting team believes that the coordination of other system elements that are owned by the same Transmission Owner, Generator Owner, or Distribution Provider are governed by their internal protection coordination quality control processes.</td></tr>
<tr><td>Tacoma Power</td><td></td><td>1. Is it the expectation of the SDT that Protection System coordination issues may be identified when Protection System Studies are performed pursuant to R1.1.1?
2. If such issues are identified, is it the intention of the SDT that these issues</td></tr>
</table>

Organization	Yes or No	Question 9 Comment
		would constitute violations of PRC-027-1, provided that the process described in PRC-027-1 for remedying these issues is followed? 3. Transmission Owners depend on each other for accurate short circuit models. As proposed, PRC-027-1 does not appear to clearly address sharing of short circuit modeling information among Transmission Owners when incremental changes are made within a Transmission Owner's system. For example, incremental changes in adjacent Transmission Owners' systems may result in a 5% change in Fault current at an Interconnected Facility when the changes are considered separately, but when the changes are considered together, the Fault current might change by 10%. While the +/- 10 % change in an Interconnected Facility's Fault current value as a trigger appears to be reasonable, the proposed standard offers no guidance or requirements concerning the accuracy of an entity's short circuit model or the methods used to determine Element impedances. This issue is most pronounced for zero-sequence impedance, and to a lesser extent negative-sequence impedance, since these parameters are used infrequently in system planning studies. It seems that some standardized approach for determining impedance parameters may need to be developed, whether in this standard or in another standard, provided that some latitude is afforded entities based upon sound engineering judgment. 4. In R2.2, why is it not sufficient to simply include the following in the parentheses: "single line to ground and 3-phase for the bus(s) under consideration"?" 5. The formulas in R2 use V for current. For clarity's sake, current should be denoted using the letter I." 6. Under R3.2, if all applicable entities agree to a schedule, was it the intention of the SDT that the agreed-upon schedule could be longer than 30 calendar days? 7. M8 requires that an entity have evidence that other entities received

Organization	Yes or No	Question 9 Comment
		information pursuant to R3.3.1 and R3.3.2. What if, despite due diligence, one or more entities do not acknowledge receipt? 8. Since notification pursuant to R3.3 is after the fact, to be compliant, an entity depends upon one or more other entities to acknowledge receipt, but there does not appear to be a regulatory requirement for them to acknowledge receipt in a timely manner, only a requirement to confirm that the changes are acceptable within 30 days of receipt pursuant to R4.3. Consequently, if Entity A notifies Entity B of changes pursuant to R3.3 in 15 calendar days, Entity B would have until 45 calendar days following the change to respond. However, by this time, Entity A might not have documentation that it met its requirements under R3.3. Another challenge with R3.3 and R4.3 is that the language seems to assume that both entities will agree to the changes. While this should usually be the case, there may be instances in which the entity receiving notice may not find the changes acceptable. 9. Additionally, the language in R4.3 may influence the entity receiving the notice to deem the changes as being acceptable, even if they are not, in order to meet the 30 calendar day timeframe. 10. Tacoma Power thanks the SDT for including Figure 4 in the Application Guidelines. 11. In Figure 5 of the Application Guidelines, why would it be necessary to check for coordination issues with Protection System settings associated with Breakers A, B, C, and D? Is this language intended to address reverse elements that are independent of communications systems? Is it intended to include bus differential, which would be the scheme commonly applied? Or, is there some other reason? 12. To what extent can this standard be enforced within a Transmission Owner's system? For example, in Figure 1 of the Application Guidelines, in addition to verifying that there are no coordination issues between Protection System

Organization	Yes or No	Question 9 Comment
		settings associated with Breaker A and, say, Breaker F, does the SDT intend that this standard could be construed to grant regulatory authority to audit that a Protection System Study was completed to verify that there are no coordination issues between Protection System settings associated with Breaker F and other breakers within Transmission Owner S's system? 13. While Protection System settings associated with Breakers A and F may be coordinated, Breaker F may not be coordinated with other Protection System settings within Transmission Owner S's system such that Protection System settings associated with Breaker A might also not be coordinated for some Faults within Transmission Owner S's system. It is believed that this type of situation should be rare and that the scope of this proposed standard should be limited to audit and enforcement of Protection Systems at the Interconnected Facilities, as depicted in Figures 1, 2, 3, and 5. Assume that there is documentation supporting coordination of Protection Systems at Interconnected Facilities. However, during a Fault, a Mis-operation occurs, and the cause of the Mis-operation is attributed to mis-coordination, despite good faith on the part of the entities to coordinate Protection Systems. Is it the intention of the SDT that this Mis-operation would be construed as a violation of PRC-027-1? For example, although they are generally addressed to some degree in Protection System Studies, but often implicitly through margins, factors of safety, etc., phenomena such as CT saturation or DC offset are not always directly analyzed in Protection System Studies and could lead to mis-coordination even if Protection System settings appear to be coordinated in documentation. 14. It is not clear what responsibility the TO has if it models a generator's short circuit capability incorrectly. 15. The proposed changes to PRC-001 (proposed version 3) are supported. 16. As a reminder to the SDT, Protection System design and application is part science and part art, and it may be difficult to thoroughly audit and enforce

Organization	Yes or No	Question 9 Comment
		the latter. Tacoma Power appreciates the opportunity to comment on the proposed standard and thanks you for your consideration of our comments.

Response: Thank you for your comment.

1. **The drafting team believes that coordination issues may be identified when Protection System Studies are performed pursuant to R1.1.1 and this is the basis for this requirement.**
2. **The drafting team believes that any coordination issues identified when Protection System Studies are performed pursuant to Requirement R1, Part R1.1.1, Part 1.1.2 or Part 1.1.3 are discovered would lead to corrective actions as identifies in the other requirements.**
3. **The drafting team believes that developing a standardized approach for determining impedance parameters is outside the scope of this project.**
4. **The drafting team believes the existing wording is appropriate and did not make your suggested change.**
5. **Per your suggestion and others, the drafting team has modified the equation to replace "V" with "I"**
6. **Under Requirement R3 Part 3.2, if all applicable entities agree to a schedule, the intention of the drafting team is that the agreed-upon schedule could be longer than 30 calendar days.**
7. **Measure M8 has been modified to indicate that information was provided within 30 days; therefore, an acknowledgement of receipt is no longer required.**
8. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**
9. **Based on comments, the drafting team removed Requirement R4, Part 4.3.**
10. **Thank you for the comment.**
11. **In Figure 5 of the Application Guidelines, it is necessary to check for coordination issues with Protection System settings associated with Breakers A, B, C, and D if there are reverse tripping elements that are independent of communications systems.**

Organization	Yes or No	Question 9 Comment
12. The drafting team believes that the requirements of PRC-027-1 extend to only to “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements for the BES and that require coordination for isolating those faulted Elements.” As stated in the text for Figure 1 of the Application Guidelines, the only Interconnected Element identified is the transmission line between Breakers A and E. **13. A Misoperation is not a violation of this standard.** **14. The Transmission Owner is identified as the entity responsible for performing the Fault current studies in Requirement R2, Part 2.1. The standard does not address incorrect modeling of a generator’s short circuit capability.** **15. Thank you for your support.** **16. Thank you for your reminder and your comments.**		
Detroit Edison		1. It is suggested that the standard include other relevant information that could be needed for a protection system study such as critical clearing times determined from stability studies. 2. In Figure 3, what Protection System Studies would be required if the Distribution Provider does not have a Protection System designed to protect BES transmission system elements? 3. Also, please clarify if the transformers in Figures 3 and 4 are BES elements. 4. Also, further clarification, including some examples, would be beneficial to explain what does and what does not constitute “Protection Systems installed to protect Transmission System Elements” by a Distribution Provider.
Response: Thank you for your comment. **1. The drafting team believes that the data required by a protection system study are discussed in the technical guideline is a suggested list. Other information such as critical clearing times may be required for a specific location’s relay coordination study and can be requested by either entity as needed.** **2. The note in the description for Figure 3 states: “A Protection System Study is required per this standard for this example if a Protection System at the Distribution Provider’s substation is designed to detect Faults on the BES Transmission System.”**		

Organization	Yes or No	Question 9 Comment
Therefore, a Protection System Study would not be required. . **3. The drafting team believes the transformers in Figures 3 and 4 are not BES Elements.** **4. Based on your comment, the drafting team has added a note to the text of Figure 3.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)		It would seem that M9 should be reworded slightly so that it is clear that the compliance burden is placed on the party sending the confirmation. It seems like it should read "demonstrating the confirmation was sent within the respective time frames" instead of "demonstrating the confirmation was achieved within the respective time frames." In other words, Requirement 4 compliance is solely for the confirming party to show evidence, not the submitting party.
Response: Thank you for your comment. **Based on comments, the drafting team revised Measure M9 to read: "Acceptable evidence for 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."**		
Lincoln Electric System		1. LES recommends additional clarity be added to explain how an entity would coordinate the efforts of the many different protection schemes - for example, pilot tripping, primary, secondary, ground overcurrent, breaker failure, LOP supervised, etc. - to determine only Elements required to isolate Faults are removed from service. Does an entity consider only its fastest scheme, slowest scheme, or all of them? 2. Additionally, is an entity to consider contingencies such as primary or secondary relay out of service, loss of communications, etc.? What about backup tripping? Until the above is addressed, an entity will have a difficult time discerning what exactly needs to be studied. 3. Please take into consideration that system protection is a complicated subject and each entity has its own philosophies on how to do it. Entities should be allowed to use their individual engineering judgment when designing their

Organization	Yes or No	Question 9 Comment
		systems and ensuring it will work to their own standards as well as in compliance with the NERC standards. 4. LES is concerned that there may be potential for mis-coordination between PRC-027-1 and PRC-004-2a. If a misoperation is defined as tripping too much out of service during an event, does the entity become instantly non-compliant with PRC-027-1 since it should have been studied not to do so? Any correlation between these two standards should be considered and clearly defined. 5. LES recommends the 24 month timeframe specified in R2.1 be extended to 60 months. Historically, fault currents tend to increase gradually over time; therefore, an entity may never see a 10% increase between studies, but will most likely see a 10% increase over a larger timeframe at which point they would never be required to perform a study.
Response: Thank you for your comment. **1. In your example, all relays responding to Fault conditions should be included in your Protection System Study.** **2. All relays responding to Fault conditions installed for the Interconnected Element should be included in your Protection System Study.** **3. The drafting team agrees with your assessment that each entity has its own philosophies on how to protect the system. The drafting team believes that PRC-027-1 does not infringe on the ability of entities to protect their elements. However, the purpose of PRC-027-1 is "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults."** **4. A Misoperation is not a violation of this standard.** **5. The drafting team believes as stated in the rational for Requirement R2 Part 2.1 that, "Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation." Specific to your question, please note that the 10% deviation is in relation to the most recent Protection System Study.**		

Organization	Yes or No	Question 9 Comment
Massachusetts Municipal Wholesale Electric Company		MMWEC endorses the comments submitted by NPCC.
Response: Thank you for your comment. **See the response to comments submitted by NPCC.**		
NPPD		1. On page 6 and 16 there are statements such as “no evidence there is widespread miscoordination between Interconnected Facilities...” and on page 16 “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.” Clarify what the need is for this standard? This proposed standard significantly increases the record keeping requirements and subsequent resources needed for each Facility owner but does not appear to have a justification. 2. I find the numerous time lines will create significant confusion and very complex data retention practices that will be difficult to track and difficult to audit. It appears the focus is more on time lines and the likely result is the content of the shared information will likely suffer due to the burden of tracking communications between entities. This draft standard includes time lines ranging from “prior to in service date, 30 days, 60 days, 90 days, 6 months, 2 years and 3 years”. I suggest fewer and longer time lines with the focus on if the sharing of information took place and not on when did it take place. 3. The SDT statement below should be generalized to the standard as a whole: ”The SDT 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 SDT 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

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td></td><td></td><td>project on schedule and confirm the changes are acceptable “prior to the in-service date,”
4. Clarify the size of generation for Distribution Providers that would make this standard applicable for all involved entities. I would expect that the BES phase II definition or registry criteria would be referenced.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team stands by the quoted statement that there is “no evidence of widespread miscoordination between Interconnected Elements.” However, because communication of changes at the interconnection or changes that effect the Protection Systems at an Interconnected Element is required for proper coordination, The drafting team believes the requirements laid out in the standard are appropriate.
2. The drafting team believes that to make PRC-027-1 measurable and enforceable, the listed times are necessary.
3. The drafting team believes they applied reasonable and appropriate time frames for the identified activities and provided flexibility by including the option to agree upon an alternate schedule where deemed appropriate.
4. Figure 3 is independent of the size of the generation. The intent is to identify that coordination is required where Protection Systems are installed for the purpose of detecting Faults on the Transmission System.</td></tr>
<tr><td>ExxonMobil Research & Engineering</td><td></td><td>PRC-001-3 has a single requirement with no associated measure. Any standard requirement whose implementation can address a reliability gap in the Bulk Electric System should possess a quality that can be measured. The SDT should modify PRC-001-3 and provide a measure for Requirement R1 or redact the standard in its entirety.</td></tr>
</table>

Response: Thank you for your comment. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, “The SPC SDT recommends 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”.**		
Progress Energy		Progress Energy request re-evaluation of time for performing Short circuit study in R 2.1. Request 36 months which is same time frame in R1.
Response: Thank you for your comment. **Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation.**		
Dairyland Power Cooperative		R2, 2.1 “Perform a short circuit study to determine the present Fault current values, not less than once every24 months.” is excessive. Yes, short circuit databases are updated annually or even more frequently at times based on system changes. However, to require a full short circuit study every 24 months is too frequent. Changes on the system don’t necessarily warrant a full short circuit study, but maybe a study for the affected area. This is adding an unnecessary burden to the industry.
Response: Thank you for your comment. **Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation at the interconnecting buses. The drafting team believes studies associated with changes that would affect the coordination in less time would be triggered by other requirements in this standard.**		
MRO NSRF		1. Recommend that the wording of R2 need be modified to allow a grace period for implementation, as was done in R1. As written, R2 requires an immediate short circuit study, even if no protection system study is required by R1.1.1. 2. The SDT, on both page 6 and 16 states that there is “no evidence there is widespread mis-coordination between Interconnected Facilities...” They

		further state on page 16 that “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.” Why, then, is this standard even needed? It adds an onerous burden of record keeping on each Facility owner without justification for doing so. 3. Since these are still zero defect standards, should exceptions be included for required operational replacements due to events (e.g. such as storms or immediate equipment replacement). When the lights are out and a technician replaces a CT or VT with a slightly different ratio but compensates by altering the relay settings, there is no way to perform an instant system protection study when the equipment change out was required to support system reliability. The NSRF understands that a “planned” changed be studied before hand, but how will this be viewed when a change is needed that is “unplanned”? Please clarify
Response: Thank you for your comment. **1. Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation at the interconnecting buses. Based on your comment, the drafting team modified Requirement R2, Part 2.1 to read: “At least once every 24 months, perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.”** **2. The drafting team is developing a standard based on a SAR accepted by the Standards Committee and is addressing directives issued by FERC in Order 693.** **3. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Requirement R3, Part 3.3 was changed to “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.”**		
Manitoba Hydro		1. Regarding R1, it is not clear what specifically the Protection System Study should include. - According the application guidelines on page 17, it states:

"Data used to determine Fault currents in performing the study", what data does this refer to?

2. Also it states that it should include "listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Interconnected Facility, and were reviewed for coordination of protective relays as part of the study". It is not clear if it should include a list of all the enabled protection elements and their settings of the protection system package or the package only. Should it include the protection system on the interconnected facilities only or on the immediate adjacent elements as well?
3. The Application guidelines say it should list any issues associated with the relay settings. It is not clear what should be considered as issues. Does a protection mis-coordination occur only under contingencies (such as primary protection element fails) consider an issue? Do backup protection elements have to coordinate with backup protection elements?
4. Regarding R2, it is not clear what fault current value should be used for the short circuit study. Should it be the total fault current of the interconnecting bus? Or should it be the total fault current of the interconnecting bus excluding the contribution from the interconnected facilities?

Response: Thank you for your comment.

1. **The drafting team declines to modify the definition of the Protection System Study but did add the following to the description in the "Guidelines and Technical Basis": "System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions." The drafting team believes that the full description in the Guidelines and Technical Basis is now adequate and appropriate.**
2. **The entity should include all protection elements reviewed for coordination. It is up to the entity to determine what and where those elements are for the particular system configuration.**
3. **It is up to the Owner to determine what is appropriate for their system and under what contingencies the relays should coordinate. Any issued identified that fall outside of their normal practice would need to be listed.**
4. **The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus**

where a Protection System Study is available per Requirement R1.”

ReliabilityFirst		ReliabilityFirst offers the following comments for consideration: 1. Requirements R1, R2 and R4 a. Requirements R1, R2 and R4 do not follow the format of a typical Results Based Standard requirement (i.e. the parent requirement simply states "the entity shall:"). Result Based Standard risk based requirements should be in the following format: "who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." ReliabilityFirst recommends modifying these three standards to conform to the Results Based Standard format. 2. Requirement R2a. ReliabilityFirst questions why Transmission Owners only need to perform a short circuit study on Interconnected Facilities and not their internal system Facilities as well (Requirement R2). ReliabilityFirst believes it would be beneficial for Transmission owners to be required to determine present fault current values (and calculate the percent deviation between the Fault current values) for all internal system Facilities. 3. Need for PRC-001-1 Requirement R1a. ReliabilityFirst believes PRC-001-1 Requirement R1 is ambiguous and believes the intent is covered in the NERC PER-003-1 standard. It will be very hard for an applicable entity to show that they are “familiar” with the purpose and limitations of protection system schemes applied in its area. Since ReliabilityFirst believes R1 does not enhance reliability, ReliabilityFirst recommends retiring PRC-001-1 Requirement R1 consistent with the effective date of the NERC PER-003-1 standard (effective date of 10/01/2012).

Response: Thank you for your comment.

1. **The standard has been reviewed by NERC Quality Review for format and content.**
2. **The previous PRC-001 only applied to coordination between TOPs, GOPs and BAs. The drafting team has chosen not to include internal facilities for two main reasons: the extreme documentation burden that would be involved for minimal benefit as most of this work is done by the same organization, and the drafting team believes that the entities’ internal facilities are completely in their control and are the responsibility of the entity. Failure to properly design and implement internal Protection Systems would be an internal lack of procedures and/or a human performance issue which are both outside the**

<table>
<tr><td colspan="3">scope of this standard.
3. This drafting team is not addressing the refinement of PRC-001-1 Requirement 1. As noted in the background section, “The SPC SDT recommends 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”.</td></tr>
<tr><td>Kansas City Power & Light</td><td></td><td>1. Requirement 1.1 of R1 states, “Perform a Protection System Study for each Interconnected Facility to verify that Protection Systems remove from service only those Elements required to isolate Faults as follows:”. The purpose of this standard should not be to remove from service only those Elements required to isolate Faults, therefore 1.1 above should state, “Perform a Protection System Study for each Interconnected Facility as follows:”.
2. Requirement 1.1.2 of R1 states, “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.” Since this Requirement is an action as a result of requirement R2 and as noted in the response to question 6 above, R2 should be deleted.
3. If the SDT is adamant about having a periodic review of fault current levels then the fault current level should be increased to 20% on the protected line. A 10% fault current change is not significant enough to require a new protection system study.
4. Requirements R4.3 and R3.3 are actions as a result of a misoperation and because there is already a standard (PRC-004) that deals with misoperations these two requirements should not be covered in this standard if changes need to be made due to misoperations they should be made in the misoperation standard (PRC-004). This standard is not intended to replace the Misoperation Standard and any requirements addressing misoperations gives FERC, NERC and the Audit Teams the wrong impression of the intent of this standard.
5. All Protection System Studies are dependent on accurate system models.</td></tr>
</table>

		Individual Entities should not be responsible for development and maintenance of an accurate Regional model or model to be used between Regions. Individual Entities should only be responsible for providing the information on their system to the Regional Entity so that an accurate model can be maintained by the RC. I propose that this standard be applicable to the Region and require the Region to maintain an accurate model that includes zero sequence impedance and is useful for Protection System Studies. This system model also needs to be accurate between Regions for Protection System Studies that span between Regions. This will require that the standard also be applicable to NERC RRO and require RRO to oversee the process of maintaining an accurate national model or equivalents that can be used between Regions. Anything less than this is placing an unfair burden and unrealistic expectation on the TO to produce and maintain an accurate model for interconnecting Protection System Studies. 6. A dispute resolution mechanism also needs to be required to provide for instances where entities cannot come to a mutual agreement. Recommend a requirement be included for entities to request applicable RC(s) to arbitrate to bring resolution to a matter.

Response: Thank you for your comment.

1. **The drafting team has modified Requirement R1, Part 1.1 to read "Perform a Protection System Study for each Interconnected Element to coordinate Protection Systems, such that the least number of power system Elements are isolated to clear Faults as follows:" to be consistent with the Purpose.**
2. **Requirement R1, Part 1.1.2 provides for a time frame to complete a Protection System Study once a notification that the short circuit current at an Interconnected Element has changed. Requirement R2 provides for a periodic review of short circuit currents. This standard will retain this requirement.**
3. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.**
4. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed**

Requirement R4, Part 4.3. The intent of Requirement R3, Part 3.3 is to communicate changes to a Protection System (including those discovered during an investigation) to an Interconnecting Entity as follows: “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.”

5. **The drafting team believes that individual entities are not responsible for regional models, they are responsible for conveying information on their own equipment and system**
6. **The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting team cannot make judgments on compliance.**

Texas Reliability Entity		1. Requirement R1.1.3: While we agree with the SDT rationale that R3 notifications may occur weeks or years prior to the change, we feel that a time frame should be included in this requirement rather than leaving it open-ended. 2. We suggest that the Protection System Study be completed at least 60 calendar days prior to the in-service date for R3.1 and within 30 days after receiving notification for R3.3. If the SDT agrees with this, then an appropriate VSL should also be drafted.

Response: Thank you for your comment.

1. **The drafting team believes there in not a single time frame that would be appropriate for every project and has chosen to not add a time frame.**
2. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**

Associated Electric Cooperative, Inc., JRO00088		1. See SERC Comments 2. Also pertaining to PRC-027-1 Page 2, Terms:, "Interconnected Facilities" definition, proposed change: Replace: “functional, operating, or corporate entities” with: “functional or operating entities” Rationale: In certain cases,

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<tr><td></td><td></td><td>independent Corporate entity is irrelevant to the planning and operations of these systems. As written, the underlying 6 G&Ts of AECI’s JRO could technically and unnecessarily be subjected to this standard for AECI's internal Facilities, and not just Interconnected Facilities between AECI and other non-JRO entities, although AECI's JROs functionally coordinate relay settings much as a large IOU’s regional departments would.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. See response to SERC Comments.
2. Based on comments, the drafting team changed Interconnected Facilities to Interconnected Elements defined as follows, Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.</td></tr>
<tr><td>Western Small Entity Comment Group</td><td></td><td>The comment group agrees with the WECC Position Paper that the standard as written requires excessive and burdensome documentation that is not needed to demonstrate coordination.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.</td></tr>
<tr><td>PPL Corporation NERC Registered Affiliates</td><td></td><td>The cutoff date of 6/18/07 for grandfathering of studies may be appropriate for TOs and DPs in light of changes over time to their systems, but the studies that originally established GO relay settings would still be valid where the equipment has stayed the same. For the reasons discussed above, there should be no applicability of PRC-027 to independent GOs, and no changes to PRC-001-1.1 because the applicable requirements.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team modified Requirement R1, Part 1.1.1 to make studies performed prior to 6/18/07 acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2. which now reads: “Provide to</td></tr>
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<tr><td colspan="3">the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each Protection System Study.”The drafting team believes the applicability of PRC-027-1 is correct and the applicability of PRC-001-3 as revised is correct.</td></tr>
<tr><td>Santee Cooper</td><td></td><td>1. The documenting, notification and replies required in this standard will put a significant strain on the time of settings personnel. While we agree that this coordination of data is very important, any simplification of the processes would help ensure that protection system staff has the time to do other critical protective system work, in addition to interconnection studies.
2. Possible suggestions would be change R2 2.1 to a longer time period, since most re-coordinations are due to changes covered in R3. “Not less than once every third year,” would fall in well with the audit schedule. Not less than once every fifth year would match TPL-001-2 draft 5.
3. Also, you could conceivably not have R3 3.3, since those are covered by the statements in 3.1 and 3.2</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained. The drafting team is not requiring a Protection System Study; only a summary of the results of the Protection System Study performed is required to be provided to the other entities. The drafting team believes the scope of a particular project will dictate the work necessary to coordinate the Protection Systems involved, and to document the coordination process.
2. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.
3. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed</td></tr>
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Requirement R4, Part 4.3. The intent of Requirement R3, Part 3.3 is to communicate changes to a Protection System (including those discovered during an investigation) to an Interconnecting Entity as follows: "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."		
Duke Energy		1. The order of the Requirements in PRC-027-1 should be put in chronological order to align with the Example Process outlined on page 22. 2. PRC-001-1:It's not clear that balloting for Project 2007-06 also includes PRC-001-3. 3. General comment - The vague language of R1 does not make it practicable for the responsible entities to implement the requirement. 4. The Purpose is limited to coordination/relationship with the applicable entities. The Purpose is vague as to whether it applies to the Bulk Electric System. 5. Requirement R1 does not clearly state a reliability outcome/benefit. It is not aimed to achieve one objective. The phrase "shall be familiar with the purpose and limitations of protection system schemes," is vague and not measurable. What does it mean to be "familiar" with in this context? Could this requirement be stated in a way that is measurable? The outcome is not obvious because of vague terminology. What will be the outcome of entities being "familiar purpose and limitations of protection system schemes?" The term "familiar" is too general to address a single activity. Although it can be inferred that familiarity with the purpose and limitations helps ensure reliability, what single reliability goal will be accomplished? 6. There is no measure specified for R1 (according to the Model: each requirement must have one or more associate measures used to objectively evaluate compliance with the requirement). What type of evidence could be used so the entities are compliant with the requirement? The Data Retention language mirrors the recommended default language. However, because there are no measures, which are "used as a guide in identifying which

		responsible entity must keep the evidence and for how long," where do the "3 years" come from? There is no supporting document or reference to a supporting document for justification of VRFs for PRC-001-3; although, there is one for PRC-027-1 (which does not mention PRC-001-3).No explanation is given for the "High" or "Severe" VRF for R1.Generally, how is the VSL said to be "Severe" if there are no measures for R1? Effective Date - There needs to be an explanation for the time lapse of more than 3 months between approval date and the effective date of the standard. Additional clarity is needed regarding performance requirements and how an entity would demonstrate compliance with R1.Requirement R1 doesn't support the Purpose statement of the standard.

Response: Thank you for your comment.

1. **The standard has been reviewed by NERC Quality Review for format and content. The Example Process is intended to present one scenario, and the drafting team has decided not to change it.**
2. **This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, "The SPC SDT recommends 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".**
3. **It is unclear to the drafting team whether your comment references PRC-001-3 or PRC-027-1. This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, "The SPC SDT recommends 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".**
4. **It is unclear to the drafting team whether your comment references PRC-001-3 or PRC-027-1. However, the drafting team has revised the Purpose statement in PRC-027-1. The new Purpose statement reads: To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.**
5. **This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, "The SPC SDT recommends 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".**
6. **Based on comments, the drafting team modified the Facility Applicability 4.2 to "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements,"**

which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard.		
Wisconsin Electric Power Company		1. The SDT is to be commended for their efforts in what is a very challenging standard to develop. 2. A Protection System Study by definition must assure that Protection Systems are “coordinated” at an Interconnected Facility. However, this standard does not establish any ownership for achieving a complete study. The interconnected entities are only capable of studying the portion of the system that they own. So, each entity performs their portion of the study and communicates it to the other entities. Thus, there is a lack of clarity in the standard about how the complete study gets done and is documented. With the possible exception of the Transmission Owner, no entity alone has the complete system model that is essential for documenting the complete coordination study. 3. There is also ambiguity on what a complete study looks like, and is subject to interpretation. It is unclear how the supplementary documents previously developed for PRC-001 apply to this standard. In the absence of such guidance, how will consistency be achieved for coordination of Protection Systems on the various types of Interconnection Facilities ? 4. It is suggested that Requirement R4.3 is extraneous and should be removed. If these changes are sufficient to trigger a study, then the timeframe for agreement is already specified in R4.1. We propose that the standard be revised to allow the entities to re-affirm the results of a previous study, when appropriate, rather than needing to perform another study. For example, perhaps the fault current has increased, but the coordination interval between devices is not appreciably changed. 5. The SDT notes in several places in the draft standard (pg 6, 16) that there is no evidence of widespread miscoordination between Interconnected Facilities, nor any evidence of misoperations caused by lack of coordination. 6. This suggests that if this standard is needed, that it should be simpler, less

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<tr><td></td><td></td><td>prescriptive, and have greater recognition of the motivation for mutual coordination that already exists. It can be argued that the tasks and time frames required in the draft standard should be left to the entities to determine.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. Thank you for your support.
2. It is expected that the owner of the Interconnected Element will complete the Protection System Study for that element. See the Figures 1-5 and accompanying explanations.
3. The drafting team is not defining what every Protection System Study should look like, just the minimum that must be included into a summary that will be provided to the Interconnected Element Owner.
4. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.
5. PRC-027-1 is replacing Requirements R2 and R3 of PRC-001-2. The drafting team is developing a standard based on a SAR accepted by the Standards Committee and is addressing directives issued by FERC in Order 693.
6. The drafting team believes that there is flexibility in the process to allow for the expertise of each entity to be used to coordinate Protection Systems.</td></tr>
<tr><td>ISO RTO Council SRC</td><td></td><td>The SDT recognizes that Requirement R1 falls outside the scope of Project 2007-06 and proposes 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. Left unaddressed, entities may be reluctant to vote to approve the PRC-001-2 changes. Changes made to a standard can cause unforeseen or unintended consequences that cannot be addressed because of limitations in the scope of the project. The SDT has no ability to address the matter without getting a change in scope of the project. This is a concern that applies to ALL standards changes as the industry seeks to revise and improve the NERC standards. A change in the Rules of Procedure or the Standards Development Procedures must be in place to recognize and deal with such occurrences.
The SDT (SRC?) is also concerned that these proposed requirements are not</td></tr>
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		conducive to NERC's stated goal of making the reliability standards more "results or performance oriented". Although many of the actions embodied in the proposed requirements should be performed, they are administrative in nature and do not in and of themselves provide results that will impact reliability. The industry needs to discuss and come to agreement on what reliability standards should look like in order to meet the NERC stated goal. The SRC also believes these requirements are not applicable for entities operating in the ERCOT Interconnection.
Response: Thank you for your comment. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "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 drafting team believes the documentation identified in the requirements is necessary to support the purpose.** **The drafting team believes PRC-027-1 applies to all applicable entities that own Protection Systems within ERCOT.**		
MWDSC		The standard requires more documentation than is necessary and providing a copy of each Protection System Study is burdensome and would not result in better performance. It should be adequate to document that studies were performed and that affected entities have agreed to the results.
Response: Thank you for your comment. **The wording of Requirement R1, Part 1.2 is "Provide to each affected Interconnected Element owner a summary of the results of each Protection System Study performed pursuant to this requirement…" Transmitting the entire PSS is not required. The receiving entity per Requirement R4 Part 4.1 shall "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Colorado Springs Utilities		1. The wording of the text under Applicability suggests that Interconnected Facilities include coordination and documentation of Transmission to Distribution interfaces. Since these are often located in different functional or

		corporate entities we feel this would require more documentation, and therefore needs clarified. 2. There are no specifications on what constitutes a significant change to a Protection System; is it a CT ratio change, a relay replacement, or anything to the whole system? For example, would a single structure replacement require notification as a line spacing change? The wording sounds good but lacks specifics that would make this a workable standard.
Response: Thank you for your comment. **1. The standard is only applicable to Distribution Providers with “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.”** **2. The drafting team believes when changes that “modifies the conditions used in the coordination of Protection Systems of the Interconnected Elements”, they must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained. For the example cited in the comment, Requirement R3 Part 3.1 states that “Changes to a transmission system Element that changes any sequence or mutual coupling impedance” and therefore would be included in the communication.**		
ATCO Electric		There are too many timelines that are hard to keep up with. The drafting team should reduce amount of timelines to a manageable amount.
Response: Thank you for your comment. **The drafting team will continue to restrain the number of timelines, however the drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.**		
Liberty Electric Power LLC		There is no generator size limit set for this standard. It should exclude generators below a threshold value. Suggest generators with an aggregate nameplate value below 500 MVA connecting through a single step-up transformer.
Response: Thank you for your comment. **The drafting team has modified the Applicability Section 4.2 Facilities to read: “Protection Systems installed for the purpose of**		

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<tr><td colspan="3">**detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”. Consequently, the standard is applicable to Generator Owners that have the Facilities described above.**</td></tr>
<tr><td>Portland General Electric Company</td><td></td><td>1. This standard, as written, requires an inordinate amount of documentation that this not in line with current fault study and protection coordination tools. When combined with the timelines, this will require a complete rework of the existing processes used for protection coordination and an additional full time protection engineer. We have no history of misoperations on interconnecting lines or of backup protection on such lines to justify any additional effort to document coordination.
2. R1 leaves open to interpretation what constitutes coordination, with many unanswered questions. What is an acceptable coordination margin? How many contingencies need to be considered? Does loss of communication need to be considered? For the evidence, would an exception report showing no coordination intervals are violated be acceptable for the “summary results of each Protection System Study”?
3. Will the responsibilities outlined in the Application Guidelines be included as part of the final standard? These may not be in line with current practices. How will this requirement be audited across utilities with different coordination practices?
4. R2 requires significant cooperation between interconnecting utilities, with each keeping track of what fault currents are being used by the other. This is not in line with the use of joint system models, allowing more frequently updated fault currents to be used. Currently, the individual system models are updated by some utilities daily then they are reconciled at least annually. Protection System Studies can be run any time in between model reconciliation, with all local changes accounted for.
5. R3.1 does not provide guidance on the timing of notification for changes; the measure M6 indicates this is for future changes, but the requirement does not.</td></tr>
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<tr><td></td><td></td><td>6. Protection engineers are rarely notified in advance of transmission line changes resulting from such things a road widenings and pole replacements. Providing this information to neighboring utilities in advance will require significant changes to line design processes. Thresholds must be established to rule out minor transmission line changes that do not significantly impact the line impedance (and thus the fault current); perhaps a 10% change in impedance would be more appropriate than the general “changes to line lengths and/or conductor size or spacing”.
7. This requirement should also include changes to facility ratings to ensure PRC-023 compliance.
8. R4 requires a significant change to work practices to support capital construction schedules and allow interconnecting utilities 30 days to review changes. The schedule laid out does not account for disagreements that lead to back-and-forth prior to achieving agreement. This requirement grants power to neighboring utilities to halt construction activities which could, in turn, create compliance violation of other Reliability standards.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team will continue to restrain the number of timelines, however the drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.
2. It is up to the Owner to determine what margins are appropriate for their system and under what contingencies the relays should coordinate.
3. The Application Guidelines are and will be part of the standard and are consistent with the requirements of the standard. The figures in the Application Guidelines are intended to be explanatory.
4. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate. This does not preclude an entity from performing this task more often.
5. 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.</td></tr>
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<tr><td colspan="3">**6. The drafting team believes when a change “modifies the conditions used in the coordination of Protection Systems of the Interconnected Elements”, it must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained. For the example cited in the comment, Requirement R3 Part 3.1 states that “Changes to a transmission system Element that change any sequence or mutual coupling impedance” and therefore would be included in the communication.**
7. The drafting team believes that FAC-009 already requires the sharing of Facility Ratings and their inclusion into the Protection System coordination standard is unnecessary.
8. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.” Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.</td></tr>
<tr><td>American Electric Power</td><td></td><td>1. We agree with the comment in the background section that the SAR written for this project was focused on System Protection Coordination, and we recommend that PRC-001 R1 should be moved to another standard more focused on operations or training. TOP-006 R3 might be a more appropriate standard for such a requirement.
2. For R1, the standard needs to clearly state the boundaries of the required study(ies). In addition, detail is needed regarding the depth of study away from the point of interconnection, and how far into the generating unit auxiliary system or interconnecting system must be evaluated.
3. Based on the redline provided where R3 and R4 have been removed, and assuming the SDT is not willing to moving the sole remaining requirement to another standard, the title and purpose of resulting PRC-001 would need to be changed.
4. If PRC-001 R1 remains as it is, the phrase “familiar with the purpose and limitations of protection system schemes” needs additional clarity. Doing so might help prevent a CAN from being developed to provide such clarity.</td></tr>
</table>

		5. AEP suggests the time requirement on R4.3 associated with R3 needs to be extended to 60 days.
Response: Thank you for your comment. **1. This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, “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”.** **2. Based on comments, the drafting team modified the Facility Applicability 4.2 to “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”, which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard.** **3. This drafting team is not addressing the refinement of PRC-001. As noted in the background section, “The SPC SDT recommends 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”.** **4. This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, “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”.** **5. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Consumers Energy		1. We feel that this is a very difficult standard to interpret consistently as written. We think a negative vote is warranted since it is confusing and unclear for our situation. Following are specific comments to support our negative vote. 2. In regard to the Process Flow Chart on page 21 - We assume this Process Flow Chart is intended as an illustrative clarification of the standard, not a supplement to the wording. The chart claims to be a “complete representation of the process” and as such should match identically or it should be eliminated as it causes confusion. It is our interpretation that the chart does not match the standard’s wording. One example if you start with an R3 emergency replacement you end up with two conflicting results.

		Under 4.3.2 you have 30 days to confirm that the changes are acceptable. Under 1.1.3 you have to do a protection study so you are given 90 days per section 1.2. This entire chart should be verified to ensure that it matches the written standard and does not result in conflicting requirements. We suggest adding the sub-requirement labels to each flow chart item for easier reference to that section of the standard. 3. In regard to Figure 3 on page 25 - The figure appears to represent the connection of a large NERC qualified generator. Does this figure also apply to a looped source distribution system or should that follow figure 4? We would like to see a definitive example that clarifies what to do for the situation where you have a looped source distribution system. 4. In regard to Figure 4 on page 26 - the figure implies that A & B can be set to overtrip C (as no study is required) which would interrupt the BES for distribution faults. This appears to be contrary to what is intended by this standard.
Response: Thank you for your comment. **1. The drafting team is striving to improve the standard through the balloting process.** **2. The drafting team has modified the flowchart based on comments and to reflect all changes made to the standard.** **3. Figure 3 is represents a generator connected to a Distribution Provider. The drafting team modified Figure 3 to indicate that the source could be a generator or a network system. The Applicability Section 4.2 Facilities states: “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”, which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard. This does not include a Protection System that would operate for a Fault on the Transmission System, if that is not its primary purpose. Figure 4 is intended to be a radial Distribution System with no source.** **4. Figure 4 is intended to illustrate a situation where no Protection System Study is required per this standard because there is no Protection System installed to detect Faults on the BES Transmission System. This does not preclude the Transmission Owner from reviewing the Protection System to ensure the system operates as designed.**		
Public Service Enterprise		We have the following additional comments:

<table>
<tr><td>Group</td><td></td><td>a. FORMATTING: Remove the bullets in 3.1 and replace with subparts 3.1.1, 3.1.2, etc.
b. With regard to R2, we suggest that the Transmission Planner be required to perform the studies described therein, not the TO.
c. Furthermore, there should be a requirement similar to that suggested in our response to #5, paragraph that each TP provide data needed by another TP needed to perform the required study. It should also address how potentially different results for the same Interconnected Facility by the several TPs should be dealt with.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
a. The drafting team has retained the format for Requirement R3, Part 3.1.
b. Although the Transmission Planner may “define system protection and control needs”, it will be the owner that is responsible for determining the implementation and coordination.
c. The drafting team believes that nothing in the requirements precludes an entity from asking for necessary data, and requirements are needed to ensure that requested data is provided. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2. The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon.</td></tr>
<tr><td>Public Utility District No. 1 of Snohomish County</td><td></td><td>We note that the formulas in R2 use V for current. For clarity’s sake, we believe current should be denoted using the letter I</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
Per your suggestions and others, the drafting team has modified the equation to replace “V” with “I”.</td></tr>
<tr><td>Sacramento Municipal Utility District</td><td></td><td>We note that the formulas in R2 use V for current. For clarity’s sake, we believe current should be denoted using the letter I.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
Per your suggestions and others, the drafting team has modified the equation to replace “V” with “I”.</td></tr>
</table>

<table>
<tr><td>Tri-State G & T</td><td></td><td>We think there needs to be a time frame associated with the calculation of the percent deviation after the fault duties are calculated. One way to accomplish that would be to eliminate 2.1 and add a 24 month requirement to 2.2., which would require the performance of a short circuit study anyway.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that the phrase “pursuant to Requirement R2, Part 2.1, using the following equation” implies that the calculation must be performed within the same 24 month period. As stated in the Rationale box supporting Requirement R2, Part 2.1: “Short circuit databases are customarily updated annually, so the SDT believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation.”</td></tr>
<tr><td>NV Energy</td><td></td><td>While we agree the Protection System Studies are necessary to verify coordination of Protection Systems, we believe that the proposed Standard requires more than the necessary amount of documentation, and therefore becomes administratively burdensome. This is contrary to the principles of the Results-Based Standards. We suggest that the evidence be limited to evidence that studies were coordinated and that the applicable entities have agreed to the results of the studies.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon. Requirement R4 Part 4.2 has been modified to read “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.” The measure for Part 4.2 is M9, which now reads “Acceptable evidence for R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that confirmation of agreement was achieved prior to implementation of any planned Protection System(s) changes.”</td></tr>
<tr><td>Exelon</td><td></td><td>None</td></tr>
</table>

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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]

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

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

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

10 — Regional Reliability Organizations, Regional Entities

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

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

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

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

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

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

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

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

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

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

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

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

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

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		

<table>
<tr><th colspan="2">Group/Individual</th><th>Commenter</th><th>Organization</th><th colspan="10">Registered Ballot Body Segment</th></tr>
<tr><th></th><th></th><th></th><th></th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th></tr>
<tr><td>19.</td><td>Group</td><td>Tom McElhinney</td><td>JEA</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="14"><table>
<tr><th></th><th>Additional Member</th><th>Additional Organization</th><th>Region</th><th>Segment Selection</th></tr>
<tr><td>1.</td><td>Ted Hobson</td><td></td><td>FRCC</td><td>1</td></tr>
<tr><td>2.</td><td>John Babik</td><td></td><td>FRCC</td><td>3</td></tr>
<tr><td>3.</td><td>Garry Baker</td><td></td><td>FRCC</td><td>5</td></tr>
</table></td></tr>
<tr><td>20.</td><td>Group</td><td>Chang Choi</td><td>City of Tacoma</td><td>X</td><td></td><td>X</td><td>X</td><td>X</td><td>X</td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="14"><table>
<tr><th></th><th>Additional Member</th><th>Additional Organization</th><th>Region</th><th>Segment Selection</th></tr>
<tr><td>1.</td><td>Travis Metcalfe</td><td>Tacoma Public Utilities</td><td>WECC</td><td>3</td></tr>
<tr><td>2.</td><td>Keith Morisette</td><td>Tacoma Public Utilities</td><td>WECC</td><td>4</td></tr>
<tr><td>3.</td><td>Chris Mattson</td><td>Tacoma Power</td><td>WECC</td><td>5</td></tr>
<tr><td>4.</td><td>Michael Hill</td><td>Tacoma Public Utilities</td><td>WECC</td><td>6</td></tr>
</table></td></tr>
<tr><td>21.</td><td>Individual</td><td>Ryan Millard</td><td>PacifiCorp</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td>X</td><td></td><td></td><td></td><td></td></tr>
<tr><td>22.</td><td>Individual</td><td>Bob Steiger</td><td>Electric Reliabilty Compliance</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td>X</td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>23.</td><td>Individual</td><td>Stephanie Monzon</td><td>PJM Interconnection</td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>24.</td><td>Individual</td><td>Erika Doot</td><td>Bureau of Reclamation</td><td>X</td><td></td><td></td><td></td><td>X</td><td></td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>25.</td><td>Individual</td><td>Pamela Hunter</td><td>Southern Company</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td>X</td><td></td><td></td><td></td><td></td></tr>
<tr><td>26.</td><td>Individual</td><td>Rowell Crisostomo</td><td>ATCO Electric</td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>27.</td><td>Individual</td><td>Dan Roethemeyer</td><td>Dynegy</td><td></td><td></td><td></td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>28.</td><td>Individual</td><td>John Falsey</td><td>Invenergy LLC</td><td></td><td></td><td></td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>29.</td><td>Individual</td><td>John Bee</td><td>Exelon and its Affiliates</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>30.</td><td>Individual</td><td>Nazra Gladu</td><td>Manitoba Hydro</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td>X</td><td></td><td></td><td></td><td></td></tr>
<tr><td>31.</td><td>Individual</td><td>Michael Falvo</td><td>Independent Electricity System Operator</td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>32.</td><td>Individual</td><td>NICOLE BUCKMAN</td><td>ATLANTIC CITY ELECTRIC COMPANY</td><td></td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>33.</td><td>Individual</td><td>Don Schmit</td><td>Nebraska Public Power District</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>34.</td><td>Individual</td><td>Michael Mayer</td><td>Delmarva Power & Light Company</td><td></td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>35.</td><td>Individual</td><td>Mark Yerger</td><td>Potomac Electric Power Company</td><td></td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>36.</td><td>Individual</td><td>Michelle R D'Antuono</td><td>Ingleside Cogeneration LP</td><td></td><td></td><td></td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

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:

29 yes

15 no

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

Based on several suggestions to modify the Purpose, 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."

The drafting team did not make several suggested changes that were submitted by individual commenters and explained in the response the reasons. Among these suggested changes were: remove the words 'coordinate' and 'components', change coordinate to 'ensure', add to clear faults' to the end, and add 'add time'.

There was a suggestion to change the title of the standard to 'Protection System Coordination for Interconnected Elements'. The drafting explained that the present title and Application section clearly sends covers this issue.

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.

Several:

5-"the desired sequence" be replaced with "an acceptable sequence"

1-Add time delayed before Protection Systems

1-Change coordinate to ensure

1- Add ‘to clear faults’ at the end
1- remove components
1- shorten to only ‘To coordinate Protection Systems for Interconnected Elements’
1- change to ‘desired sequence to properly isolate Faults’
1- add ‘settings’ after Protection systems
2-

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 intended 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 intended 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 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.		
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		

<table>
<tr><td colspan="3">the Purpose and the definition of Protection System Coordination Study, ensures that faults are cleared within their critical clearing times.</td></tr>
<tr><td>Flathead Electric Cooperative, Inc.</td><td>No</td><td>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.</td></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>ISO RTO Council Standards Review Committee</td><td>No</td><td>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</td></tr>
</table>

		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-

<table>
<tr><td colspan="3">001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.</td></tr>
<tr><td>SMUD</td><td>No</td><td>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.</td></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>City of Tacoma</td><td>No</td><td>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.</td></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>Southern Company</td><td>No</td><td>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.</td></tr>
<tr><td colspan="3">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.”</td></tr>
</table>

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<tr><td>NextEra Energy</td><td>No</td><td>The end of the sentence should read: . . . . desired sequence and time during Faults.</td></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>Essential Power, LLC</td><td>No</td><td>The expression "the desired sequence" should be replaced with "an acceptable sequence," since the GO and TO may not have the same desires.</td></tr>
<tr><td colspan="3">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.”</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>No</td><td>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?.</td></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>Texas Reliability Entity</td><td>No</td><td>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?.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The drafting team believes operating in the intended sequence during Faults includes the idea of properly isolating Faults.</td></tr>
<tr><td>Ameren</td><td>Yes</td><td>(1) Ameren supports the SERC Protection & Control Subcommittee comments and hereby includes them by reference rather than repeating them all.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. Please see the response to the SERC Protection & Control Subcommittee comments (SERC RRO)</td></tr>
<tr><td>Dominion</td><td>Yes</td><td>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</td></tr>
</table>

		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: Interconnected 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:

26 yes

19 no

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. The drafting team included the following note in the standard: 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 could 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. 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

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>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 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?</td></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>ReliabilityFirst</td><td>No</td><td>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.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.</td></tr>
</table>

Organization	Yes or No	Question 2 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 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

Organization	Yes or No	Question 2 Comment
		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 equipment we are really talking about here might be helpful in the absense of a settled definition of a BES element.
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.		
JEA	No	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.
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."		
Madison Gas and Electric Company	No	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.
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.		
Southwest Power Pool	No	Our concern with the way the definition is worded relates to how to prove

Organization	Yes or No	Question 2 Comment
		compliance between separate entities as well as entities within a vertically integrated utility. How would a Registered Entity actually show that the proper 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.

Organization	Yes or No	Question 2 Comment
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:** **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

Organization	Yes or No	Question 2 Comment
		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 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

Organization	Yes or No	Question 2 Comment
		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 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

Organization	Yes or No	Question 2 Comment
		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 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

Organization	Yes or No	Question 2 Comment
		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 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

Organization	Yes or No	Question 2 Comment
		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 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-

Organization	Yes or No	Question 2 Comment
		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 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: ?

Organization	Yes or No	Question 2 Comment
		Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)? 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). Domion 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**		

Organization	Yes or No	Question 2 Comment
of the results of the PSCS would be sufficient for use by all entities."		
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

Organization	Yes or No	Question 2 Comment
		because by definition of BES, there are no BES elements to study.
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	

Organization	Yes or No	Question 2 Comment
Electric Reliabilty Compliance	Yes	
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:

12 no

34 yes

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

Organization	Yes or No	Question 3 Comment
		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 (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.

Organization	Yes or No	Question 3 Comment
		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 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

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>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?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The time frame was increased to 60 months based on the majority of 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.
3. The “owner” is the functional entity that owns the Protection System.</td></tr>
<tr><td>Ingleside Cogeneration LP</td><td>No</td><td>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.</td></tr>
<tr><td colspan="3">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.</td></tr>
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<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>Illinois Municipal Electric Agency</td><td>No</td><td>Illinois Municipal Electric Agency supports comments submitted by Florida Municipal Power Agency.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. See response for Florida Municipal Power Agency.</td></tr>
<tr><td>Wisconsin Electric Power Company</td><td>No</td><td>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.</td></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>SMUD</td><td>No</td><td>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.</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>
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<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>Clark Public Utilities</td><td>No</td><td>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 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).</td></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>LG&E and KU Services</td><td>No</td><td>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</td></tr>
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Organization	Yes or No	Question 3 Comment
		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 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.		

Organization	Yes or No	Question 3 Comment
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	
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	

Organization	Yes or No	Question 3 Comment
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	
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	

Organization	Yes or No	Question 3 Comment
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:

36 yes

9 no

Summary of Specific Comments

1 –this requirement was confusing to understand and execute. In addition they did not like the varying time lines in the whole standard.

2 –indicated that this requirement should only apply to the TO the GO should never need to get involved in this requirement.

2 –indicated that the philosophies and protection schemes should determine the review period.

1 –the exchange of information should occur more often (Bi-annually).

3 –indicated that this requirement should not apply to single owners where one person or one department performs the coordination.

1 –technical justification should not be required for relays and schemes that are not affected by current they want to exclude these schemes from the standard as well as other exclusions.

1 –if a technical justification is valid today then that justification will be valid until modifications are made to the relaying scheme or settings. Why require justification every 60 months.

Note: Some the responses to my question where the same as the question 3 comment which should be considered when drafting a response.

Changes that should be conceded are modifications to the notification and documentation requirements when a single owner is involved or a single person/department similar to the rational used in Requirement R1. Should these exceptions/notations be added to the requirements or measure?

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 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.		
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.

Organization	Yes or No	Question 4 Comment
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 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

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>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.</td></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>Exelon and its Affiliates</td><td>No</td><td>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 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.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The drafting team allows an entity (a GO in your case) to provide a technical justification</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
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.
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.		

Organization	Yes or No	Question 4 Comment
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	
City of Tacoma	Yes	
PacifiCorp	Yes	
Electric Reliabilty Compliance	Yes	
PJM Interconnection	Yes	

Organization	Yes or No	Question 4 Comment
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, Inc.	Yes	
Wisconsin Electric Power Company	Yes	
NextEra Energy	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 4 Comment
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 the TO should perform Add verbiage here related to change suggested by Kevin if accepted		

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:

31 yes

13 no

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 is in violation of

Organization	Yes or No	Question 5 Comment
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 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.		

Organization	Yes or No	Question 5 Comment
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 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

Organization	Yes or No	Question 5 Comment
		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 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

Organization	Yes or No	Question 5 Comment
		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 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. 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: The situation you describe 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 Transmission Operator. For example, what if the solution is to leave a significantly

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>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?</td></tr>
<tr><td colspan="3">**Response: The situation you describe is outside the scope of PRC-027-1.**</td></tr>
<tr><td>Essential Power, LLC</td><td>No</td><td>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.</td></tr>
<tr><td colspan="3">**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.**
The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>Bureau of Reclamation</td><td>No</td><td>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.</td></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>Bonneville Power Administration</td><td>No</td><td>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</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		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. Based on yours' and other stakeholder comments, the drafting team revised Requirement R4 separating it into two requirements, Requirements R4 and R5.		
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 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

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.</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>Southwest Power Pool</td><td>No</td><td>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??</td></tr>
<tr><td colspan="3">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 is 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[am1].</td></tr>
<tr><td>DTE Electric</td><td>Yes</td><td>None</td></tr>
<tr><td>City of Tacoma</td><td>Yes</td><td>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?</td></tr>
<tr><td colspan="3">Response: Thank you for your support. The drafting team revised the flow chart to be consistent.</td></tr>
<tr><td>FirstEnergy Corp</td><td>Yes</td><td>We agree with Part 4.1 of Requirement 4, but we have comments regarding Part 4.2 and have stated below in Question 8.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
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	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 5 Comment
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

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:

31 Yes

8 no

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

Organization	Yes or No	Question 6 Comment
		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 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		

Organization	Yes or No	Question 6 Comment
section above.		
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

Organization	Yes or No	Question 6 Comment
		standard. In response to our previous comment, 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. 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.

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.		
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

Organization	Yes or No	Question 6 Comment
		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 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	Yes	There should be consistency between standards on this point.

Organization	Yes or No	Question 6 Comment
Council		
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	

Organization	Yes or No	Question 6 Comment
Dynegy	Yes	
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:

30 yes

10 no

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

Organization	Yes or No	Question 7 Comment
		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 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

Organization	Yes or No	Question 7 Comment
		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 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.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. Please see statement related to the future of PRC-001 in the summary of comments section above.		
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

Organization	Yes or No	Question 7 Comment
		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. 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.		

Organization	Yes or No	Question 7 Comment
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 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

Organization	Yes or No	Question 7 Comment
		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-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	

Organization	Yes or No	Question 7 Comment
ISO RTO Council Standards Review Committee	Yes	
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	

Organization	Yes or No	Question 7 Comment
American Transmission Company	Yes	
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[p2]

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:

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 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. Because the retirement of the requirements in PRC-001 are contingent upon PRC-027-1 and PER-005-2 becoming effective, your suggestion is not possible.** **c. The drafting team has followed the Drafting Team Guidelines in developing at least one Measure for each Requirement. No change made to the standard.**	
Seminole Electric Cooperative Inc.	(1) In proposed PRC-027-1 R2, Seminole believes that the Reliability Coordinator (RC)

Organization	Question 8 Comment
	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. (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 not long-term planning time horizon functions. No change made to the standard.

(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. No change made to the standard.

(3) The 10% change is based on the total Fault current available at the interconnecting bus.

<table>
<tr><th>Organization</th><th>Question 8 Comment</th></tr>
<tr><td colspan="2">(4) The drafting team believes the Application Guidelines provide sufficient guidance on 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.</td></tr>
<tr><td>Manitoba Hydro</td><td>(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 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.</td></tr>
</table>

Organization	Question 8 Comment
	(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?. (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

Organization	Question 8 Comment
	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.

(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 appropriate. No change made to the standard.

(10) The drafting team has made the suggested changes.

(11) ???????????????

(12) The drafting team has made the suggested changes.

Organization	Question 8 Comment
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

<table>
<tr><th>Organization</th><th>Question 8 Comment</th></tr>
<tr><td></td><td>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 coordination for isolating those faulted Elements.?</td></tr>
<tr><td colspan="2">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) The drafting team has changed the Applicability section to remove the separate 4.2.1.</td></tr>
<tr><td>Southern Company</td><td>(a) The purpose statement for PRC-001-3 needs to be changed to match the content of</td></tr>
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<tr><td></td><td>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.</td></tr>
<tr><td colspan="2">**Response: Thank you for your comments.**
(a) The drafting team will consider the change in numbering back to PRC-001 from PRC-027, but coordinating the change in the existing PRC-001 with the requirements of PRC-027 has precluded that.
(b) The drafting team has followed the Drafting Team Guidelines by developing at least one Measure to each Requirement. No change made to the standard.
(c) The drafting team apologizes for that oversight. A new version with the formula was made available on the NERC web site on June 21, 2013.
(d) The timeline is 30 days following the change(s).
(e) The drafting team has made the suggested change to Requirement R3, Part R3.3.
(f) The drafting team believes that entities will recognize the benefit in cooperating when changes are proposed on Interconnected Elements. The drafting team also believes that it is very likely that the commenting entity is simply projecting its behavior onto other, more reasonable entities…</td></tr>
<tr><td>Pepco Holdings</td><td>1) The SDT states that ?the requirements in the proposed Reliability Standard PRC-027-1</td></tr>
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	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 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

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	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 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

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	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 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

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	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." No change made to the standard.** **4) The drafting team added a footnote to Requirement, Part 3.3 as suggested in your comments.** **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 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

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	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 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

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	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) (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.

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	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) The drafting team believes that the format of the data request is best left to the requesting entity. The drafting team believes the evidence required in the measure is appropriate and necessary to show that the PSCS has been completed. No change made to the standard.** **d) The drafting team believes that the format of the study submittal is best left to the submitting entity. The drafting team believes the 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

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<tr><td></td><td>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%.</td></tr>
<tr><td colspan="2">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 changes suggested as it believes there is no improvement in the meaning.
2) The drafting team implemented 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 believes that if changes are made to the Transmission system that do 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.</td></tr>
<tr><td>Dominion</td><td>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.</td></tr>
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	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 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

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<tr><td></td><td>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?.)</td></tr>
<tr><td colspan="2">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 made to the standard.
2) 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.
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 made to the standard.
4) The drafting team has changed the Applicability section to remove the separate 4.2.1.
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 suggested change has been made to the figures.</td></tr>
<tr><td>Bureau of Reclamation</td><td>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</td></tr>
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	(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 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**

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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 suggestion does not convey the intent of the drafting team. The technical justification is included to exempt the entity from needing to evaluate the fault current at the interconnecting bus. No change made to the standard.** **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 desired 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 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

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	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 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

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<tr><td></td><td>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.</td></tr>
<tr><td colspan="2">Response: Thank you for your comments.
a. The drafting team allowed the use of technical justification exemptions for the types of Protection Systems thatyou described. It added that technical justification exemption to Requirement R1, Part 1.1.1.
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. PRC-001 COMMENT
d. PRC-001 COMMENT</td></tr>
<tr><td>Essential Power, LLC</td><td>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. -</td></tr>
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Organization	Question 8 Comment
	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 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 has made the suggested change to Requirement R3, Part R3.3.**
b. **PRC-027 is replacing the Protection System coordination section from PRC-001.**
c. **PRC-001 COMMENT**

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<tr><th>Organization</th><th>Question 8 Comment</th></tr>
<tr><td>Associated Electric Cooperative, Inc.</td><td>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.</td></tr>
<tr><td colspan="2">Response: Thank you for your comment.
The drafting team believes that, if a Joint Registration Organization has responsibility for all components of the Protection Systems associated with an Interconnected Element, then PRC-001 would not apply to those Protection Systems.</td></tr>
<tr><td>ATCO Electric</td><td>Can the drafting team draw all timelines in 4 requirements together in a chart to see how these timelines fit together for an entity?</td></tr>
<tr><td colspan="2">Response: Thank you for your comment.
Is this something that the SDT supports?</td></tr>
<tr><td>DTE Electric</td><td>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.</td></tr>
<tr><td colspan="2">Response: Thank you for your comment. The drafting team agrees with your comments but there is not a current standard requiring that entities 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</td></tr>
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<tr><th>Organization</th><th>Question 8 Comment</th></tr>
<tr><td colspan="2">disagreement between entities when one entity finds that the fault current has changed by 10%.</td></tr>
<tr><td>Texas Reliability Entity</td><td>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.</td></tr>
<tr><td colspan="2">Response: Thank you for your comment. Your understanding of equipment owner responsibilities for performing a PSCS in accordance with the draft standard is correct.</td></tr>
<tr><td>Dynegy</td><td>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?</td></tr>
<tr><td colspan="2">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 Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”. There are too many organizational structures in the industry for this drafting team to estimate how many GOs, TOs, or DPs will have applicable Protection Systems.</td></tr>
<tr><td>Illinois Municipal Electric Agency</td><td>1. Illinois Municipal Electric Agency (IMEA)supports comments under Question 8 submitted by the SERC EC Protection and Control Subcommittee.
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</td></tr>
</table>

Organization	Question 8 Comment
	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. **Considerations for the comments you support were provided in the drafting team's direct responses to IMEA's comments.**
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 Interconnected Elements of the BES, this standard would not apply to coordination of those Protection Systems. In consideration of your concern, Figure 3 has been annotated to clarify that the Generator or Network System depicted at the bottom of the figure does not have Protection Systems installed for the purpose of detecting Faults on BES Elements.**
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 term's use 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 Interconnected Elements of the BES and that require coordination for isolating those faulted Elements".**

Organization	Question 8 Comment
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 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

Organization	Question 8 Comment
	Standard PRC-001 as a basis for system protection coordination.

Response: Thank you for your comment. PRC-027-1 is intended to “pare out” the requirements of PRC-001 that are associated with actual “coordination” of Protection System 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*, as well as 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.

Organization	Question 8 Comment
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: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 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

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<tr><th>Organization</th><th>Question 8 Comment</th></tr>
<tr><td></td><td>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.</td></tr>
<tr><td colspan="2">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 Interconnected Element. This 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. The drafting team has made the suggested changes.
3. PRC-001 Comment</td></tr>
<tr><td>Duke Energy</td><td>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.</td></tr>
<tr><td colspan="2">Response: Thank you for your comment.
1. The drafting team believes the example given – “engineering analyses or assessments” – provides entities the ability to apply their own engineering expertise and practice in documenting a technical reason why changes in fault current, based upon the entity’s own scheme design and/or application, do not affect the coordination of the Protection Systems involved.
2. The drafting team has revised the figure to provide additional clarity that the Distribution Provider S depicted in Figure 4</td></tr>
</table>

Organization	Question 8 Comment
does not own a Protection System installed for the purpose of detecting faults on the BES. However, it should be noted that the Protection Systems owned by Transmission Owner R would operate and, since the Distribution Provider's system depicted in Figure 4 is only serving load, de-energize the distribution station and pose no further risk to the BES. Further, operation of Breaker C by the DPs protection system (for faults on/in the transformer or low-side bus) would not affect the transmission line between the TO's Breakers A and B.	
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 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. **PRC-001 comment.**	

Organization	Question 8 Comment
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 suggested change has been made to the figures[TWM3].	
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

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<tr><td></td><td>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 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.</td></tr>
<tr><td colspan="2">Response: Thank you for your comment.
1. PRC-001 comment.
2. The drafting team has made the suggested revision to the mapping document.
3. May be a valid observation. Team discussion.
4. The drafting team believes that entities making changes or additions to Protection Systems associated with an Interconnected Element must communicate the proposed changes to the other entities that will be affected by the change if systems are to be properly coordinated (R3), and that they must know who those entities are in order to provide such necessary communication.</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>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. 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</td></tr>
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<tr><th>Organization</th><th>Question 8 Comment</th></tr>
<tr><td></td><td>demonstrate compliance. Suggested rewording of the Requirement:
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.</td></tr>
<tr><td colspan="2">Response: Thank you for your comment.
1. PRC-027-1 has been through several NERC quality reviews.[fb4] PRC-001 comment.</td></tr>
<tr><td>Madison Gas and Electric Company</td><td>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 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</td></tr>
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Organization	Question 8 Comment
	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 there is a reliability benefit in ensuring that all existing Protection Systems on Interconnected Elements have been reviewed.**
3. **PRC-027-1 is intended to "pare out" the requirements of PRC-001 that are associated with actual "coordination" of Protection System 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*, as well as 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. **PRC-001 Comment**

Organization	Question 8 Comment
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: 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 has revised the figure to provide additional clarity that, though the Distribution Provider S depicted in Figure 4 does not own a Protection System installed for the purpose of detecting faults on the BES and, therefore, is not**	

Organization	Question 8 Comment
	required to perform a PSCS, the TO(s) associated with the line between Breakers A and B, must perform the PSCS. 3. PRC-001 Comment.
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?: ?, 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

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<tr><th>Organization</th><th>Question 8 Comment</th></tr>
<tr><td></td><td>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.</td></tr>
<tr><td colspan="2">Response: Thank you for your comment.
a. The drafting team has revised the Applicability Section to read: ???? Suggestion to list schemes excluded.
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 there is a reliability benefit in ensuring that all existing Protection Systems on Interconnected Elements have been reviewed.
d. The drafting team has revised the Applicability Section to read: ???? Suggestion to list schemes included.</td></tr>
<tr><td>ReliabilityFirst</td><td>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</td></tr>
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<tr><th>Organization</th><th>Question 8 Comment</th></tr>
<tr><td></td><td>2) Requirement R2, Part 2.2 - Within both the clean and redline version of the posted 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.</td></tr>
<tr><td colspan="2">Response: Thank you for your comment.
1. The[fb5] drafting team believes the example in parenthetical form provides the examples in a clear manner.
2. The issue with the equation has been corrected.[fb6]</td></tr>
<tr><td>Clark Public Utilities</td><td>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</td></tr>
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Organization	Question 8 Comment
	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 has added a footnote to Requirement R3 (Footnote 1) to address the issue you point out.	
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 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.?

Organization	Question 8 Comment
	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 has made the change you suggested.**
2. **Requirement R2 addresses the periodic performance of fault current studies, using an entity's short circuit model, in order 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.**

<table>
<tr><th>Organization</th><th>Question 8 Comment</th></tr>
<tr><td colspan="2">3. The drafting team has revised the flowchart to provide clarity[fb7].
4. Team: I can’t remember where we landed on this. Are we inferring you should have a “read receipt” without saying that, or did we decide only evidence of transmittal of the information was necessary?
5. The wording for Figure 5 has been revised to address your comment.</td></tr>
<tr><td>Idaho Power Co.</td><td>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.</td></tr>
<tr><td colspan="2">Response: Thank you for your comment. Your understanding of process regarding Figure 1 is correct.
Team: Do we need to clarify any language in R2?</td></tr>
<tr><td>CenterPoint Energy</td><td>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 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</td></tr>
</table>

Organization	Question 8 Comment
	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 there is a reliability benefit in ensuring that all existing Protection Systems on Interconnected Elements have been reviewed. 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 related to performance of Protection Systems during faults, replaces those requirements, and corrects the applicability of the requirements to the equipment owners.	
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. The drafting team believes this is a data request that is addressed by TOP-003-2 - Operational Reliability Data.	
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.	
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:

Organization	Question 8 Comment
	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. Requirement R3, Part 3.1. is only applicable to the provision of details of changes "…when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)." Therefore, if a planned relay replacement does not affect the conditions used in the coordination of Protection Systems associated with an Interconnected Element, there would be no requirement to provide the details of the project or to perform a PSCS.	
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 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

Organization	Question 8 Comment
	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 purposefully 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 SDT believes that the outcome of this standard being approved will be that the requirements associated with System Protection Coordination, already stipulated by PRC-001-1, Requirements R3 & R4, will be more clearly defined for assuring proper coordination of Protection Systems associated with Interconnected Elements of the BES, and that these requirements will be assigned to the appropriate entities, i.e. the equipment owners rather than the equipment operators.**
2. **The drafting team modified Figure 4 to address your concern.**
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**

Organization	Question 8 Comment
	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

Consideration of Comments

Project 2007-06 System Protection Coordination

The System Protection Coordination Drafting Team thanks all commenters who submitted comments on draft 2 of PRC-027-1**.** The standard was posted for a 30-day public comment period from November 16, 2012 through December 17, 2012. Stakeholders were asked to provide feedback on the standard through a special electronic comment form. There were 82 sets of comments, including comments from approximately 220 different people from approximately 157 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]

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

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	1
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
9.	Donald Weaver	New Brunswick System Operator	NPCC, NPCC	2
10.	David Kiguel	Hydro One Networks Inc.	NPCC, NPCC	1

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

11.	Christina Koncz	PSEG Power LLC	NPCC, NPCC	5
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC, NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC, NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC, NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC, NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC, NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC, NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC, NPCC	5
19.	Brian Robinson	Utility Services	NPCC, NPCC	8
20.	Ben Wu	Orange and Rockland Utilities	NPCC, NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC, NPCC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light Co.	RFC	1, 3
2.	Alvin Depew	Pepco Holdings Inc	RFC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Steve Alexanderson P.E.	Western Small Entity Comment Group			X	X					X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Russ Schneider	Flathead Electric	WECC	3, 4
2.	Russell A. Noble	Cowlitz County PUD No. 1	WECC	3, 4, 5
3.	Rick Paschall	Blachly-Lane Electric Cooperative	WECC	3
4.	Rick Paschall	Central Electric Cooperative	WECC	3
5.	Rick Paschall	Consumers Power	WECC	1, 3
6.	Rick Paschall	Clearwater Power Company	WECC	3
7.	Rick Paschall	Douglas Electric Cooperative	WECC	3
8.	Rick Paschall	Fall River Rural Electric Cooperative	WECC	3
9.	Rick Paschall	Northern Lights	WECC	3
10.	Rick Paschall	Lane Electric Cooperative	WECC	3
11.	Rick Paschall	Lincoln Electric Cooperative	WECC	3
12.	Rick Paschall	Raft River Rural Electric Cooperative	WECC	3
13.	Rick Paschall	Lost River Electric Cooperative Lost River Electric Cooperative	WECC	3

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

14.	Rick Paschall	Salmon River Electric Cooperative	WECC	3
15.	Rick Paschall	Umatilla Electric Cooperative	WECC	1, 3
16.	Rick Paschall	Coos-Curry Electric Cooperative	WECC	3
17.	Rick Paschall	West Oregon Electric Cooperative 4	WECC	3
18.	Rick Paschall	Pacific Northwest Generating Cooperative	WECC	3, 4, 8
19.	Rick Paschall	Power Resources Cooperative	WECC	6

4.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jose Landeros	IID	WECC	1, 3, 4, 5, 6

5.	Group	Joseph DePoorter	Midwest Reliability Organization NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Tom Breene	WPS	MRO	3, 4, 5, 6
4.	Jodi Jenson	WAPA	MRO	1, 6
5.	Ken Goldsmith	ALTW	MRO	4
6.	Alice Ireland	XCEL (NSP)	MRO	1, 3, 5, 6
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Kayleigh Wilkerson	LES	MRO	1, 3, 5, 6
9.	Joseph DePoorter	MGE	MRO	3, 4, 5, 6
10.	Scott Nickels	RPU	MRO	4
11.	Terry Harbour	MEC	MRO	1, 3, 6
12.	Marie Knox	MISO	MRO	2
13.	Lee Kittelson	OTP	MRO	1, 3, 5, 6
14.	Scott Bos	MPW	MRO	1, 3, 5, 6
15.	Tony Eddleman	NPPD	MRO	1, 3, 5
16.	Mike Brytowski	GRE	MRO	1, 3, 5, 6
17.	Dan Inman	MPC	MRO	1, 3, 5, 6

6.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X		X	X				

<table>
<tr><th rowspan="2">Group/Individual</th><th rowspan="2">Commenter</th><th rowspan="2">Organization</th><th colspan="10">Registered Ballot Body Segment</th></tr>
<tr><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th></tr>
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<table>
<tr><th></th><th>Additional Member</th><th>Additional Organization</th><th>Region</th><th>Segment Selection</th></tr>
<tr><td>1.</td><td>Jonathan Hayes</td><td>Southwest Power Pool</td><td>SPP</td><td>NA</td></tr>
<tr><td>2.</td><td>Robert Rhodes</td><td>Southwest Power Pool</td><td>SPP</td><td>NA</td></tr>
<tr><td>3.</td><td>Greg Froehling</td><td>Rayburn Electric</td><td></td><td>NA</td></tr>
<tr><td>4.</td><td>Tiffany Lake</td><td>Westar Energy</td><td>SPP</td><td>1, 3, 5, 6</td></tr>
<tr><td>5.</td><td>Valerie Pinnamonti</td><td>American Electric Power</td><td>SPP</td><td>1, 3, 5</td></tr>
<tr><td>6.</td><td>Clem Cassmeyer</td><td>Western Farmers</td><td>SPP</td><td>1, 3, 5</td></tr>
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<tr><td>7. Group</td><td>Michael Jones</td><td>National Grid and Niagara Mohawk (A National Grid Company)</td><td>X</td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
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<table>
<tr><th></th><th>Additional Member</th><th>Additional Organization</th><th>Region</th><th>Segment Selection</th></tr>
<tr><td>1.</td><td>Michael Schiavone</td><td>Niagara Mohawk (A National Grid Company)</td><td>NPCC</td><td>3</td></tr>
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</td></tr>
<tr><td>8. Group</td><td>Chris Higgins</td><td>Bonneville Power Administration</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td>X</td><td></td><td></td><td></td><td></td></tr>
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<tr><th></th><th>Additional Member</th><th>Additional Organization</th><th>Region</th><th>Segment Selection</th></tr>
<tr><td>1.</td><td>Dean Bender</td><td>SPC Technical Svcs</td><td>WECC</td><td>1</td></tr>
<tr><td>2.</td><td>Deanna Phillips</td><td>FERC Compliance</td><td>WECC</td><td>1, 3, 5, 6</td></tr>
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<tr><td>9. Group</td><td>Mary Jo Cooper</td><td>GP Strategies</td><td>X</td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
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<tr><th></th><th>Additional Member</th><th>Additional Organization</th><th>Region</th><th>Segment Selection</th></tr>
<tr><td>1.</td><td>Elizabeth Kirkley</td><td>City of Lodi</td><td>WECC</td><td>3</td></tr>
<tr><td>2.</td><td>Colin Murphey</td><td>City of Ukiah</td><td>WECC</td><td>3</td></tr>
<tr><td>3.</td><td>Douglas Draeger</td><td>Alameda Municipal Power</td><td>WECC</td><td>3</td></tr>
<tr><td>4.</td><td>Angela Kimmey</td><td>Pasadena Water and Power</td><td>WECC</td><td>1, 3</td></tr>
<tr><td>5.</td><td>Blaine Ladd</td><td>California Pacific Electric Company</td><td>WECC</td><td>3</td></tr>
<tr><td>6.</td><td>Ken Dize</td><td>Salmon River Electric Co-op</td><td>WECC</td><td>3</td></tr>
<tr><td>7.</td><td>Michael Knott</td><td>Granite State Electric</td><td>NPCC</td><td>3</td></tr>
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<tr><td>10. Group</td><td>Brenda Hampton</td><td>Luminant</td><td></td><td></td><td></td><td></td><td></td><td>X</td><td></td><td></td><td></td><td></td></tr>
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<tr><td>1.</td><td>Rick Terrill</td><td>Luminant Generation Company LLC</td><td>ERCOT</td><td>5</td></tr>
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<tr><td>11. Group</td><td>Louis Slade</td><td>Dominion</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td>X</td><td></td><td></td><td></td><td></td></tr>
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<tr><td>1.</td><td>Steve Edwards</td><td>Electric Transmission</td><td>SERC</td><td>1, 3</td></tr>
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Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

2.	Sean Iseminger	Fossil & Hydro	SERC	5
3.	Chip Humphrey	Fossil & Hydro	NPCC	5
4.	Connie Lowe	NERC Compliance Policy	RFC	5, 6
5.	Jeff Bailey	Nuclear	NPCC	5

12.	Group	David Greene	SERC Protection and Controls Subcommittee (PCS										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bridget Coffman	Santee Cooper	SERC	
2.	Steve Edwards	Dominion, Virginia Power	SERC	
3.	Ernesto Paon	MEAG Power	SERC	
4.	Greg Davis	Georgia Transmission	SERC	
5.	James Evans	SCANA	SERC	
6.	Paul Nauert	Ameren	SERC	
7.	George Pitts	TVA	SERC	
8.	David Greene	SERC	SERC	

13.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative Inc. and Southwest Transmission Cooperative Inc.	WECC	1, 4, 5
2.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
3.	William Hutchison	Southern Illinois Power Cooperative	SERC	1
4.	Chris Bradley	Big Rivers Electric Corporation	SERC	
5.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
6.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
7.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
8.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
9.	Amber Anderson	East Kentucky Power Cooperative	SERC	1, 3, 5

14.	Group	Sasa Maljukan	Hydro One Networks Inc.	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Difilippo	Hydro One Networks Inc.	NPCC	1
2.	David Kiguel	Hydro One Networks Inc.	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
15.	Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	make haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

16.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Service	FRCC	3

17.	Group	Charles Yeung	Certain Members of the ISO RTO Council		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Campoli	NYISO	NPCC	2
2.	Ali Miremadi	CAISO	WECC	2
3.	Bill Phillips	MISO	RFC	2
4.	Steve Myers	ERCOT	ERCOT	2
5.	Ben Li	IESO	NPCC	2

18.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Detweiler	FirstEnergy	RFC	1, 3, 4
2.	Bill Duge	FirstEnergy	RFC	5
3.	Robert Loy	FirstEnergy	RFC	5
4.	Brian Orians	FirstEnergy	RFC	5
5.	Larry Raczkowski	FirstEnergy	RFC	1, 3, 4, 5, 6

19.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

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

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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
4.			WECC	5
5.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
6.			NPCC	6
7.			SERC	6
8.			SPP	6
9.			RFC	6
10.			WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Group	Greg Rowland	Duke Energy	X		X		X	X				

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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
22.	Group	Thomas McElhinney	JEA	X		X		X					

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	Joe Uchiyama	US Bureau of Reclamation	X				X				X	
24.	Individual	Rowell Crisostomo	ATCO Electric	X									
25.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
26.	Individual	Janet Smith	Arizona Public Service Company	X		X	X	X	X	X			
27.	Individual	Ed Croft	Operational Compliance	X		X		X					
28.	Individual	ryan millard	pacificorp	X		X	X	X					
29.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
30.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
31.	Individual	Jim Watson	Dynegy					X					
32.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
33.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					
34.	Individual	Andrew Z. Pusztai	American Transmssion Company, LLC	X									
35.	Individual	Si Truc PHAn	Hydro-Quebec TransEnergie	X									
36.	Individual	NICOLE BUCKMAN	ATLANTIC CITY ELECTRIC COMPANY			X							
37.	Individual	Don Jones	Texas Reliablity Entity										X
38.	Individual	Patrick Brown	Essential Power, LLC					X					
39.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
40.	Individual	Mark Yerger	Potomac Electric Power Compan			X							
41.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
42.	Individual	Scott Miller	MEAG Power	X									
43.	Individual	Wryan Feil	Northeast Utilities	X		X		X					
44.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
45.	Individual	Thad Ness	American Electric Power	X		X		X	X				
46.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
47.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
48.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
49.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
50.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
51.	Individual	David Jendras	Ameren	X		X		X	X				
52.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
53.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
54.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
55.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
56.	Individual	Jim Howard	Lakeland Electric	X		X		X	X				
57.	Individual	Larry Watt	Lakeland Electric	X		X		X	X				
58.	Individual	Michael Moltane	ITC	X									
59.	Individual	Michael Falvo	Independent Electricity System Operator		X								
60.	Individual	Anthony Jablonski	ReliabilityFirst										X
61.	Individual	Jonathan Meyer	Idaho Power Co.	X									
62.	Individual	Brian Murphy	NextEra Energy	X		X		X	X				
63.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
64.	Individual	Saul Rojas	New York Power Authority	X		X		X	X			X	
65.	Individual	Stephanie Monzon	PJM Interconnection		X								
66.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
67.	Individual	Richard Vine	California Independent System Operator	X	X	X	X	X	X				
68.	Individual	John Bee	Exelon Corporation and its affiliates										
69.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
70.	Individual	Mike Hirst	Cogentrix Energy Power Management, LLC					X					
71.	Individual	Marie Knox	MISO		X								
72.	Individual	Jim Cyrulewski	JDRJC Associates								X		
73.	Individual	Clay Young	SCE&G	X		X		X	X				
74.	Individual	Daniela Hammons	CenterPoint Energy	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
75.	Individual	Greg Davis	Georgia Transmission Corporation	X									
76.	Individual	Scott McGough	Georgia System Operations Corporaton			X							
77.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
78.	Individual	Angela P Gaines	Portland General Electric Co	X		X		X	X				
79.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
80.	Individual	Karen Webb	City of Tallahassee	X		X		X					
81.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
82.	Individual	Rich Salgo	NV Energy	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"
Illinois Municipal Electric Agency	Florida Municipal Electric Agency
Hydro-Quebec TransEnergie	NPCC
ATLANTIC CITY ELECTRIC COMPANY	Pepco Holdings Inc and Affiliates
Delmarva Power & Light Company	Potomac Electric Power Company, Transmission Owner (Segment 1)
Potomac Electric Power Compan	Pepco Holdings Inc and Affiliate
MEAG Power	Essential Power, LLC
Northeast Utilities	Northeast Power Coordinating Council Inc. (NPCC)1040 Avenue of the Americas10th FloorNew York, NY 10018
Consolidated Edison Co. of NY, Inc.	NPCC, the Northeast Power Coordinating Council
Flathead Electric Cooperative, Inc.	Support both the previous comments of Bonneville Power Administration and the comments of the Western Small Entity Comment Group
Lincoln Electric System	MRO NSRF

Organization	Supporting Comments of “Entity Name”
The United Illuminating Company	Northeast Power Coordinating Council (NPCC)
Lakeland Electric	FMPA
Lakeland Electric	Please see FMPA comments.
New York Power Authority	NPCC
California Independent System Operator	The California ISO is in support of, and has signed on with, the comments submitted by the Standards Review Committee (SRC) (ISO/RTO Council).
MISO	MISO supports the comments submitted by the Standards Review Committee (SRC).
JDRJC Associates	Midwest ISO
Georgia System Operations Corporaton	Georgia Transmission Corporation
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing

1. **Based on stakeholder comments, the drafting team modified the Purpose of this standard to "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults." Do you agree with this Purpose? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Quick summary:

16 no with comments

11 yes with comments

23 yes with no comments

2 no vote with comments 1 VSL comment and one 'least number" issue

Observations: The majority of No votes involved the inclusion of "the least number of power system Elements are isolated to clear Faults."

Organization	Yes or No	Question 1 Comment
Nebraska Public Power District	No	It seems the real purpose of this standard is "To coordinate BES Protection Systems for Interconnected Elements". The rest of the statement is already covered as part of the protection systems design which will involve coordination or not depending on any special issues or existing design limits.
Response: Thank you for your comment. The Purpose has been revised based on your and others' comments to read: PURPOSE HERE		
ACES Standards Collaborators	No	(1) We disagree with the inclusion of the "least number of power system Elements" in the purpose. The purpose should be to simply coordinate the Protection Systems for Interconnected Elements. While trying to minimize the

Organization	Yes or No	Question 1 Comment
		number of Elements that should be removed from service is a laudable goal, it will create an incentive for auditors to determine if there is a better way to protect the registered entities systems. How else could an auditor know that the absolute minimum of Elements have been determined unless they tried optimize the zone of protection themselves. The use of different but related terms causes confusion. For instance, what is the difference among "power system Elements," "Elements," and "Interconnected Elements"? Based on the definition of "Element," we assume "power system Elements" is intended to be the same. If so, we suggest dropping "power system" to avoid confusion. (2) Similar to the purpose statement, the Applicability Section, (4.2) Facilities is unclear. The statement "Interconnected Elements of the BES that require coordination for isolating those faulted Elements" includes superfluous language. In general, NERC enforces standards against the BES. Thus, it is not necessary to include "of the BES." To ensure absolute clarity, we suggest the definition of Interconnected Element be modified to specifically limit it to the BES as well. Also, we recommend striking everything after Interconnected Elements in the purpose statement as it is unnecessary and provides no additional clarification on the Facilities to which the standard applies. (3) Because no generic questions asking for additional comments was provided, we are providing our concerns that do not fall under one of the specific questions asked of the drafting team here. (4) Please change the wording of Part 1.2 as the current wording has some unintended consequences. We think "to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement" should be changed to "to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of the associated Protection System Study." The current language literally reads that the TO, GO, and DP shall provide the PSS results to itself. It

Organization	Yes or No	Question 1 Comment
		also reads that all the Protection System Studies for a TO, GO, or DP must be provided to the other protection system owners of all of the Interconnected Elements even if the other owners only own protection systems for one of the TO, GO, or DP's Interconnected Elements. As an example, consider that TO X shares two separate Interconnected Elements with TO Z and GO A. The Interconnected Element between TO X and TO Z is called Tie-line B and the Interconnected Element between TO X and GO A is GSU C. The requirement would literally require TO X to share its Protection System Study results for both Tie-line B and GSU C with both GO A and TO Z even though, GO A has no interest in Tie-Line B and TO Z has no interest in GSU C. This could be solved with the simple edit described above. (5) We find that addition of "For each Facility associated with an Interconnected Element on its System" in R2 confusing. First, what is an associated Facility? Second what is intended by the use of Facility instead of Element? Considering Interconnected Facility in the last draft was change to Interconnected Element and Facility was used in this requirement, it would appear some delineation is meaning is intended between Element and Facility. Since Element and Facility have nearly the same meaning in the NERC Glossary of Terms that delineation is unclear and we would appreciate further explanation of the intent. (6) We found the inclusion of quotes on the phrase "Protection Systems installed to detect faults on the BES Transmission System" confusing. There is no reference. We suggest removing the quotes as they are superfluous. The meaning is still communicated without them. If they remain, please provide a reference. We assumed it came from section 4.2. If the quote did come from that section, it is not quite correct. It is missing "for the purpose of detecting" and "faults" is not capitalized (7) The purpose statement of PRC-001-3 needs to be further modified. With the deletion of all of the requirements but Requirement R1, the purpose to "ensure system protection is coordinated among operating entities" is no

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>longer achieved.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The Purpose has been revised based on your and others’ comments to read: PURPOSE HERE
2. The definition of Interconnected Element has been revised based on your and others’ comments to read: INTERCONNECTED ELEMENT HERE
3. NA
4. The suggested change has been made
5. The language in R2 has been clarified
6. The phrase you mentioned has been modified to accurately reflect the language in the Figure from which it was taken.
7. The SDT has proposed the following Measure, M1, to be added to PRC-001-3: Acceptable evidence for Requirement R1 is dated documentation showing that each Transmission Operator, Balancing Authority, and Generator Operator has been provided explanations of the protection system schemes applied in its area.</td></tr>
<tr><td>Certain Members of the ISO RTO Council</td><td>No</td><td>Although the SRC agrees that protection systems should strive to interrupt only those elements closest in to a fault to avoid excessive interruptions, there are situations where it is necessary to trip elements beyond those that only interrupt the fault. To set a result for “...the least number of power system Elements are isolated to clear Faults” misses the primary goal for a reliability standard meant to protect the interconnected bulk electric grid. NERC standards should always have the underlying purpose to prevent cascading failures that affect interconnected systems. The stated Purpose must recognize that the “least number of power system Elements are isolated to clear Faults to maintain system integrity”. For example, a relay scheme could isolate a fault on a generator connected between two line terminals by opening the breakers on both ends of the line. This would fulfill the Purpose of “least number of power system Elements”, however, a protections scheme for that segment of transmission line may require that the next terminal along that line also be interrupted in order to prevent an unintended increase in load to a particular</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		element due to the opening of the breakers closest to the fault.
Response: Thank you for your comment. The Purpose has been revised based on your and others' comments to read: PURPOSE HERE		
Northeast Power Coordinating Council	No	1. By restricting the coverage to "... Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults" there is a significant gap in reliability created by the exclusion of elements such as loss of field, out-of-step, etc. 2. An incomplete Protection System Study negates all the work needed to satisfy this Standard. Perhaps through referencing the NERC technical reference document entitled "Power Plant and Transmission Protection Coordination", there could be a reference to which protection elements are going to be covered in this Standard and likewise what Standards will cover the protection elements not covered by this Standard. 3. As identified by the Drafting Team, there may be no evidence of mis-coordination between traditional protections that detect faults, but for co-ordination of generator loss of excitation protection settings or out of step relaying during a fault condition - is that meant to be covered in this Standard or elsewhere? 4. The latest draft of PRC-019-1 indicates studies conducted under that standard are for steady state conditions, not fault conditions. PRC-023 provided clear direction on what protection elements to mitigate and even provided options on how to mitigate those elements. PRC-027 should provide the similar effective vehicle to convey at least the "what" for Protection System coordination during faults between entities, and will allow entities to perform and document consistent Protection System Studies. 5. The term "coordination" is not well defined. Does it mean ensuring owners of all terminals of a line, transformer, etc. are aware of each other's protection

Organization	Yes or No	Question 1 Comment
		system design and settings, especially when the design, settings, and physical system changes? Developing a formal definition to be included in the NERC Glossary should be considered.
Response: Thank you for your comments. **1. The coordination of non-fault-related Protection Systems such as what you describe is not within the scope of this standard.** **2. Because there are different Protection System designs and philosophies, the drafting team cannot specify which Protection Systems require coordination.** **3. The drafting team believes that conditions such as those that you suggested are expected to be remedied under other standards. For example, out-of-step conditions should be identified and mitigation coordinated and implemented as a result of a transmission system assessment required in the TPL standards.** **4. The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.** **5. The drafting team agrees that “coordination” is not well-defined. Rather than trying to develop a definition in the NERC Glossary of Terms, the drafting team chose to express what was intended for coordination in this standard.**		
CenterPoint Energy	No	CenterPoint Energy believes the purpose should use wording similar to that being proposed for the definition of “Protection System Study” instead of developing and utilizing different wording for the purpose statement. CenterPoint Energy recommends the purpose be stated as follows: “To coordinate Protection Systems for Interconnected Elements, such that Protection Systems operate as desired for clearing postulated short circuit Fault events.”
Response: Thank you for your comment. The Purpose has been revised read: PURPOSE		
NV Energy	No	Concerned that the Applicability and Purpose are encroaching upon Distribution elements, outside the statutory authority of the NERC Standards process

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. Per the Applicability, the standard applies only to Distribution Providers that own “Protection Systems installed for the purpose of detecting Faults on BES Elements and that require coordination for isolating those faulted Elements.” This standard does not pertain to distribution (non BES) Elements.		
Exelon Corporation and its affiliates	No	Exelon agrees with the Purpose statement as stated, however the questions and layout of this comment form doesn't provide an area to provide comments as to why we are voting negative. While requiring periodic coordination studies between entities is laudable, it is unnecessary. The coordination of a protection system, by nature, is tested every time it operates. We already have a standard, PRC-004-2, that requires all transmission protection system operations to be analyzed for correctness and any misoperations reported, along with corrective action plans to mitigate their cause. Our experience indicates the bulk of protection system misoperations are not caused by a lack of coordination studies. This standard, as written, continues to be vague and will lead to an inconsistent application of the requirements. Most importantly, we believe this standard is ill advised. Coordination of protection systems between entities was not a factor in the 2003 blackout. As such it clearly goes beyond the mandate of the 2003 blackout recommendations. Implementation of this standard will add little to the reliability of the bulk electric system while adding substantially to the amount of time and money an entity spends simply on compliance activities. Contrary to the goal of enhancing reliability, this standard will simply dilute available resources to the detriment of reliability.
Response: Thank you for your comment. The drafting team believes there is a reliability benefit to review and ensure proper Protection System coordination on existing Protection Systems associated with Interconnected Elements prior to potentially being identified by a misoperation. The standard requiring coordination (PRC-001) already exists.		
FirstEnergy	No	In regard to the purpose statement, FirstEnergy supports the response submitted by the RFC Protection Subcommittee which is repeated here for convenience. The purpose should mirror the objectives of the Protection Systems Study. “To coordinate Protection Systems for Interconnected Elements,

Organization	Yes or No	Question 1 Comment
		such that the Protection Systems operate in the desired sequence.” The reasons being that an entity may choose to overtrip distribution transformer (non-BES) protection, to employ zone 1 extension schemes, or for other valid reasons trip more than the least number of Elements to clear a Fault.
Response: Thank you for your comment. The Purpose has been revised based on your and others’ comments to read: PURPOSE		
Pepco Holdings Inc & Affiliates	No	The language in the Statement of Purpose needs to be reworded. The phrase “such that the least number of power system Elements are isolated to clear faults” may restrict certain protection practices in widespread use today, where coordination on tapped distribution facilities is achieved via auto-reclosing rather than via coordinated time delays. For example, a BES line (protected by a high speed DCB or POTT pilot scheme) is tapped by a distribution provider as demonstrated in Figure 3 of the Application Guidelines. Very often for distribution taps like these, rather than requiring the distribution provider to establish a costly transmission class pilot scheme terminal at breaker C with communication links to A & B, it is common to let the pilot scheme reach into (but not thru) the transformer at C. For faults in the transformer the high speed transformer relays will operate to trip and lockout breaker C. However, the pilot scheme at A & B will also trip simultaneously. Breaker C will lockout and A & B will auto-reclose to restore the line. Coordination is achieved via auto-reclosing. For faults on the line, A & B will trip via the pilot scheme, and if generation happens to be running either C will trip, or the generator will trip depending on scheme design. Reclosing at A & B would be delayed and / or voltage supervised to ensure generation has been removed prior to auto-reclosing. In the above scenarios since the line tripped for a fault in the transformer, or the generator tripped for a fault on the line, it would violate the requirement that “the least number of power system Elements are isolated to clear faults”. The language used in the proposed definition of Protection System Study is better; using the phrase “demonstrates ... Protection Systems operate in the desired sequence for clearing faults”. The problem here is who

Organization	Yes or No	Question 1 Comment
		determines what is the “desired sequence”? Would a scheme, which is purposely designed as described above and acknowledged by the Transmission Planner and Transmission Operator, be considered to operate in the “desired sequence” for clearing faults? The language in the standard needs to be re-visited to enable these types of protection interfaces with distribution providers having limited generation resources connected downstream. Also, if system reliability was truly an issue for this example, the interconnection should not have been a simple tap on the line, but rather a ring bus should have been established at the interconnection point. In conclusion, we suggest re-wording the Purpose to read: “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence for clearing Faults.” This statement is consistent with the stated definition of the Protection System Study, on which the measures of this standard are based.
Response: Thank you for your comment. The Purpose has been revised based on your and others’ comments to read: PURPOSE		
Florida Municipal Power Agency	No	The primary purpose of protection system coordination is to ensure faults are cleared expeditiously and well under the critical clearing time, with the stated purpose of minimizing the number of elements isolated as a secondary consideration, not a primary consideration. As such, there is no recognition of the importance of remote back-up protection that backs up primary and secondary protection, but, does not necessarily share the same goal of minimizing number of elements tripped, but, does share the goal of clearing a fault within the critical clearing time.
Response: Thank you for your comment. The drafting team agrees with your statement that critical clearing time is important. The drafting team revised the Purpose: however, the team believes that minimizing the elements isolated is simply a part of accomplishing that clearing time. The coordination between the primary and backup protection that you address has to take place, otherwise there would always be isolation of more than is necessary to clear the faults.		
Bonneville Power Administration	No	The Purpose given assumes that the most important outcome of a protection

Organization	Yes or No	Question 1 Comment
		system operation is that the least number of power system elements are isolated to clear a fault. While it is true that it is usually desirable to prevent parallel paths from opening, in many cases it might be perfectly acceptable for adjacent elements to operate. BPA believes it may be more economical to have a protection system that isolates elements in addition to the faulted element if the isolation of the additional elements does not result in problems for the BES. A suggested Purpose statement that takes this philosophy into account is: To insure that separate Functional Entities properly coordinate with each other the protective systems for elements that interconnect their electrical systems so that only the intended power system elements will be isolated to clear a fault.
Response: Thank you for your comment. The Purpose has been revised read: PURPOSE		
Essential Power, LLC	No	The purpose is laudable, but the means by which it is to be achieved needs more work. The Application Guidelines section of PRC-027 makes reference to, “the entity performing the Protection System Study [for R1],” but the standard provides no indication of who this should be. This responsibility is simply assigned to, “Each Transmission Owner, Generation Owner, and Distribution provider.” The obligation placed on GOs by use of the word “each” in R1 cannot be fulfilled, however, except under the circumstance of having a vertically-integrated utility. An independent GO does not have knowledge of the TO’s system, and in a deregulated market is not allowed to have such knowledge. The TO and TOP are provided with detailed information of the GO’s equipment, however, and therefore perform all interconnection-related studies. This is as it should be, because changes in the transission don’t matter to a GO. 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 in the TO’s system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations

Organization	Yes or No	Question 1 Comment
		remaining as per PRC-001, i.e. reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should say so, rather than pulling in all GOs regardless of whether or not it makes any sense for them to be involved. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performend by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.
Response: Thank you for your comment. 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 proper coordination of the Protection Systems covered by this proposed standard.		
Cogentrix Energy Power Management, LLC	No	Note Repeat from above: The purpose is laudable, but the means by which it is to be achieved needs more work. The Application Guidelines section of PRC-027 makes reference to, “the entity performing the Protection System Study [for R1],” but the standard provides no indication of who this should be. This responsibility is simply assigned to, “Each Transmission Owner, Generation Owner, and Distribution provider.” The obligation placed on GOs by use of the word “each” in R1 cannot be fulfilled, however, except under the circumstance of having a vertically-integrated utility. An independent GO does not have knowledge of the TO’s system, and in a deregulated market is not allowed to have such knowledge. The TO and TOP are provided with detailed information of the GO’s equipment, however, and therefore perform all interconnection-related studies. This is as it should be, because changes in the transission don’t matter to a GO. 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

Organization	Yes or No	Question 1 Comment
		multiple Elements is in the TO's system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e. reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should address that specifically. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performend by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.
Response: Response: Thank you for your comment. 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 proper coordination of the Protection Systems covered by this proposed standard.		
PPL Corporation NERC Registered Affiliates	No	1. The purpose of this study should be "To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the proper sequence." The least number of Elements to clear a Fault may not always be the case for some Protection Systems. 2. The TO and TOP are provided with detailed information of the GO's equipment and therefore perform all interconnection-related studies. Independent generators do not modify Protection Systems in response to changes to the Fault current at an interconnecting bus, generators just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Equipment involving sequencing the tripping of multiple Elements is in the TO's system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e., reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should specifically address those GOs, rather than pulling in all GOs. The most that could reasonably be asked of independent GOs under R1 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 a detailed level of evidence could not be asked of the GO.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The Purpose has been revised to read: PURPOSE
2. The drafting team believes that although the Transmission Owner may provide the majority of the data and work associated with this standard, the Generator Owner shares responsibility to ensure proper coordination of the Protection Systems covered by this proposed standard.</td></tr>
<tr><td>Wisconsin Electric Power Company</td><td>No</td><td>The purpose should mirror the objectives of the Protection System Study: “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence.” There are cases where industry practice is to “overtrip”, for example, for a tapped non-BES distribution transformer fault by tripping BES line breakers and reclosing. Also it may be a common practice to use zone 1 extension or acceleration schemes. There can be good reasons for intentionally tripping more than “the least number of Elements to clear a Fault”. The Purpose statement as currently written is in conflict with these valid industry practices, and needs to be modified.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The Purpose has been revised based on your and others’ comments to read: PURPOSE</td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>1. The reliability objective of this standard should be to insure that there is an agreement between two interconnected entities of relay protection schemes and relay protection settings for the interconnected facilities.</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		This is achieved if there is documentation stating that the Interconnected operating companies have reached agreement on protection schemes and protective relay settings. This standard should only require documentation that neighboring owners are talking and agreeing with one another in relation to protection and control. 2. The purpose in the draft standard makes it appear that you are in violation of this standard any time the system has a misoperation because of relay setting regardless of whether both parties have agreed on the settings used, but the measures tend to measure agreement with the other entity. PRC-004 is the standard for misoperation reporting and misoperation mitigation.
Response: Thank you for your comment. **1. The drafting team does not see a conflict between the language in the standard and your statement "This standard only requires documentation that neighboring owners are talking and agreeing with one another in relation to protection and control." The measures provide examples of documentation that prove compliance with the requirements for 'providing data' and 'confirming agreement'.** **2. A Misoperation is not a violation of PRC-027-1.**		
US Bureau of Reclamation	Yes	1) We agree to isolate the least number of power system elments during a fault. However, PRC-027 & PRC-001 are lack of a statement which elements be reviewed by entities. It seems like it is upto utilities to decide wchich elements to be reviewed and studied for. For the comliance purpose, how does Autority judge the reviews/documents were meeting PRC-027? 2) Pg. 2- Definitions of Terms Used in Standard- "Interconnected Element: An Element that electrically joins separate Functional Entities, includingthose Functional Entities that are a part of the same Registered Entity." -The Interconnected Element definition should be expanded upon and attached figures added showing what is and is not an interconnected element relative to the generator and generation owner.

Organization	Yes or No	Question 1 Comment
		3) Page 2 - The term “Functional Entities” as used in the definitions for “Interconnected Element” should include a definition. 4) Pg. 4- A.5 -“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.” -The paragraph should be more specific as to whether the “fault clearing” referenced is used for primary transmission line protection or primary generator/generator step-up transformer protection. Namely, does what is addressed in PRC-027-1 exclude fault clearing used for primary generator/generator step-up transformer protection? 5) Pg. 8- R3.- 3.1- “ o New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios.”- The sentence should be changed to read- “ o New installation, replacement with different types, or modification of: fault clearing protective relays or protective function settings, related communication systems, related current transformer ratios and voltage transformer ratios.” 6) Last paragraph on page 26 starting with “Protection Systems installed to detect faults on the BES...” has some great examples (especially the last sentence of that paragraph) of the intent of PRC-027. I think it would be useful to move or copy this type of verbiage to the beginning of the document and use it in the definitions to accomplish what Pete has commented on below.

Response: Thank you for your comments

1. **The drafting team believes that the “elements be reviewed by entities” are clearly identified in the definitions and Applicability sections.**

Organization	Yes or No	Question 1 Comment
2. The drafting team believes that Figures 1-5 demonstrate the intent of an "Interconnected Element'. **3. The definition of Interconnected Element has been changed to: INTERCONNECTED ELEMENT** **4. This standard does include those aspects of "primary generator/generator step-up transformer protection" which may require coordination with other owners. An example would be back-up distance protection or ground overcurrent protection.** **5. The drafting team believes the definition of Protection Systems (NERC Glossary of Terms) provides adequate clarity with regards to these components. The drafting team therefore declines to incorporate your suggested changes.** **6. The drafting team disagrees and declines to make the suggested change.**		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with question 1, we have the following general comment: The purpose statement and R1.2 refers to Elements within the 'power system' which is not defined, while the 'Facilities' refers to 'Elements of the BES' and the 'Requirements' reference Interconnected Element on a particular entities' 'System' or 'transmission system'. Should these be consistent or has this been done purposefully?
Response: Thank you for your comments. The drafting team modified the language to make it consistent.		
SERC Protection and Controls Subcommittee (PCS	Yes	Based on the SDT response to our Draft 1 comment regarding the use of 'coordination', we understand 'coordination' in the Title and Purpose to mean the technical aspect of relay coordination.
Response: Thank you for your comments. The drafting team agrees with your statement.		
Georgia Transmission Corporation	Yes	Based on the SDT response to our Draft 1 comment regarding the use of 'coordination', we understand 'coordination' in the Title and Purpose to mean the technical aspect of relay coordination.
Response: Thank you for your comments. The drafting team agrees with your statement.		
Dominion	Yes	1). Dominion appreciates the SDT's agreement that in PRC 001 there were

Organization	Yes or No	Question 1 Comment
		different interpretations of the term "coordination. Based on the SDT response to our Draft 1 comment regarding "coordination", we now understand that 'coordination' in PRC 027 Title and Purpose is referring to the technical aspects of coordinating relay settings. 2). Please reconsider Dominion previous recommendations to change the Title. "Protection System Interconnected Element Coordination for Performance During Faults" or "Protection System Coordination for Interconnected Elements" have more specificity and meaning to the standards intent for coordinating relays on interconnections.
Response: Thank you for your comments. **1. The drafting team agrees with your statement.** **2. Based on your comment, the title of the standard has been changed to "Interconnected Element Protection System Coordination for Performance during Faults."**		
American Transmssion Company, LLC	Yes	However, ATC recommends that the Purpose statement in the Standard be modified by adding the word "intended" :"To coordinate Protection Systems for Interconnected Elements, such that the least number of intended power system Elements are isolated to clear Faults."
Response: The Purpose has been revised based on your and others' comments to read: PURPOSE HERE		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration agrees that it is appropriate that PRC-027-1 is self-contained throughout. Even though the Purpose statement is not necessarily mandatory and effective, it is conceivable that the previous version would lead a Compliance Enforcement Authority to require evidence that fault studies account for relay performance governed by other NERC standards. This could result in the assessment of two penalties for the same violation - a double

Organization	Yes or No	Question 1 Comment
		jeopardy condition that should be avoided.
Response: Thank you for your support. The Purpose has been revised to read: PURPOSE HERE		
Duke Energy	Yes	The Purpose statement could be improved by striking the phrase “least number of power system Elements are isolated to clear Faults”, and inserting the following phrase from the definition of Protection System Study: “Protection Systems operate in the desired sequence for clearing Faults”. Some entities may choose to “over-trip” for certain Faults.
Response: Thank you for your comment. The Purpose has been revised based on your and others’ comments to read: PURPOSE HERE		
Independent Electricity System Operator	Yes	We agree with the purpose statement, but suggest 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.
Response: Thank you for your comment. The drafting team believes that settings are not the only aspect of Protection Systems that can impact the stated purpose.		
Hydro One Networks Inc.	Yes	We agree with this Purpose statement and we commend the drafting team for moving this standard in the right direction. 1. However, in line with our previous comments from the first posting, there still seems to be a significant gap in reliability by not identifying what elements of the Protection System need to be co-ordinated between entities. Perhaps this can even reside in the Application Guide. 2. A poor or incomplete Protection System Study is worthless and negates all the work needed to satisfy this standard. 3. As identified by the drafting team, there may be no evidence of mis-

Organization	Yes or No	Question 1 Comment
		coordination between traditional protections that detect faults, but for co-ordination of say generator loss of excitation protection settings or out of step relaying during a fault condition - is that meant to be covered in this standard or elsewhere? 4. The latest draft of PRC-019-1 indicates studies conducted under that standard are for steady state conditions - not fault conditions. PRC-023 provided clear direction on what protection elements to mitigate and even provided options on how to mitigate those elements. We feel PRC-027 is an effective vehicle to convey at least the "what" for Protection System co-ordination during faults between entities and will allow entities to perform and document consistent Protection System Studies.
Response: Thank you for your comments and support. **1. Because there are different Protection System designs and philosophies, the drafting team cannot specify which Protection Systems require coordination.** **2. The drafting team agrees with your comment.** **3. The drafting team believes that conditions such as those that you suggested are expected to be remedied under other standards. For example, out-of-step conditions should be identified and mitigation coordinated and implemented as a result of a transmission system assessment required in the TPL standards.** **4. The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.**		
Ameren	Yes	We are voting negative for three reasons, one provided below and two are included in response to Question #3. Ameren also supports the SERC Protection & Control Subcommittee (PCS) comments and hereby includes them by reference rather than repeating them all. (1) We request that the SDT replace "detect Faults on the BES Transmission System" with "protect the BES Transmission System" in all three places where it

Organization	Yes or No	Question 1 Comment
		appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry.
Response: Thank you for your comment. The drafting team used the term ‘detect Faults on the BES Transmission System’ to indicate those Protection Systems that may require review with other owners Protection Systems. The drafting team revised the phrase to read “installed for the purpose of detecting Faults on BES Elements” for consistency with the Facilities section of the Applicability. It is also noted that the identified interpretation was for the term ‘transmission Protection Systems’ which is not used in this Standard.		
Western Small Entity Comment Group	Yes	
Imperial Irrigation District (IID)	Yes	
Midwest Reliability Organization NERC Standards Review Forum	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
National Grid and Niagara Mohawk (A National Grid Company)	Yes	
GP Strategies	Yes	
Luminant	Yes	
seattle city light	Yes	
Tennessee Valley Authority	Yes	
Salt River Project	Yes	

Organization	Yes or No	Question 1 Comment
Operational Compliance	Yes	
pacificorp	Yes	
Southern Company	Yes	
Dynegy	Yes	
Texas Reliablity Entity	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
Entergy Services, Inc. (Transmission)	Yes	
City of Austin dba Austin Energy	Yes	
ITC	Yes	
Idaho Power Co.	Yes	
Sacramento Municipal Utility District	Yes	
Xcel Energy	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to

Organization	Yes or No	Question 1 Comment
		90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: Thank you for your support. **Al M to review and provide answer**		
Western Electricity Coordinating Council		We agree that unnecessary power system Elements should not be isolated to clear Faults, but question the statement that the “least number of power system Elements should be isolated.” Reliability should be the goal. There may be situation where different isolation schemes both work, but perhaps one that isolates one or two more elements is more reliable.
Response: Response: Thank you for your comment. The Purpose has been revised based on your and others’ comments to read: PURPOSE HERE		

2. The drafting team is proposing two definitions for use only with PRC-027-1 as follows: Interconnected Element: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity Protection System Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults. Do you agree with these definitions, if not please provide specific suggestions for change in the comment area.

Summary Consideration:

Quick summary:

25 no with comments

5 yes with comments

25 yes with no comments

1 no vote with comments VSL issue

Studies within one company: 7 comments related to this issue.

The definition of Functional Entity was commented by many

Several folks didn't like the use of PSS as an abbreviation

Various suggestions for modifications to the definitions- mainly the PSS

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	No	At our company there is one engineering group doing Protection System Studies for all Functional Entities and for multiple Registered Entities. Reliability is not enhanced by requiring a single engineering group to document and be audited for coordination with itself. An Interconnected Element should be defined as an element that electrically joins facilities that are controlled by separate operating companies and Protection Studies are done by separate engineering groups.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. **The drafting team disagrees with your suggested definition of Interconnected Element.** **The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.**		
ACES Standards Collaborators	No	We recommend modifying the definition of Interconnected Element such that is dependent on actual registered entity ownership rather than functional entities. As an example, a generation Element would only be considered an Interconnection Element if the GO and TO were separate corporate entities. If the functions were the same registered entity, coordination would already occur and the generation Elements should not be considered an Interconnected Element. To do otherwise will only cause significant compliance problems that may not support reliability. A utility that owns generation and transmission may not have a clear point of interconnection. This would be especially true for units installed prior to the advent of open access in the mid-1990s. If the point of interconnection is not well defined, how can an Interconnected Element be defined? It would be arbitrary to pick the GSU or an Element in the switchyard. Furthermore, focusing on ownership would actually make the proposed standard consistent with the existing PRC-001-2. That standard does not explicitly require coordination among different function entities within the same registered entity. Interconnection Element definition is proposing an administrative burden of having to coordinate within the same registered function. Documenting coordination efforts made to external functions is reasonable for reliability; however, keeping records of internal coordination is unnecessary. What would an entity be required to show if there was only one protection system engineer in the organization? Would that single person be required to document coordination among him/her self? We feel that this portion of the definition should be struck - it is more appropriate to clarify the

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>coordination of protection system elements should be among external registered entities in the requirements. There should not be any requirement for internal protection system coordination, especially not in a definition.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team revised the definition of Interconnected Element; however, we disagree with your example - just because the TO and GO are part of the same Registered Entity does not necessarily mean the same technical groups are involved in the required Protection System Coordination Studies.
The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.</td></tr>
<tr><td>American Electric Power</td><td>No</td><td>1. AEP recommends replacing all references to “generator Protection Systems” with “Generator Owner equipment that provides backup system protection”, and suggest adding language to the standard for clarification. The scope of Generator Owner Protection Systems applicable to this standard is not clear from the verbiage within the standard or the definition of Interconnected Element. AEP believes that the SDT did not intend to require the GO to include all generator Protection Systems under this standard (as shown in Figure 2 on page 25 and Figure 5 on page 28 of the clean draft), but instead meant to limit the scope of relaying to be coordinated to only the Generator Owner equipment that provides backup system protection.
2. AEP agrees with the definition of Protection System Study, however, we disagree with using the acronym PSS within the standard as PSS is also the recognized acronym for Power System Stabilizer. Usage of this acronym (for example, in the Process Flow Chart) would cause unnecessary confusion.</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **1. The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.** **2. The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS).**		
PPL Corporation NERC Registered Affiliates	No	As per this version, the standard's protection study requirement seems excessive. The definition of a Protection System Study needs to include identification of the party responsible for performing this work, which should be the TO for the reasons discussed above.
Response: Thank you for your comment. The drafting team believes that although the TO may provide the majority of the data and work associated with this Standard, the GO also has a role to ensure proper coordination of the protection systems covered by this proposed standard.		
CenterPoint Energy	No	CenterPoint Energy recommends the term "Protection System Study " be defined as follows: "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing postulated short circuit Fault events."
Response: Thank you for your comment. The drafting team believes the definition as noted is sufficient.		
Sacramento Municipal Utility District	No	Clarification is necessary for the definition of "Interconnected Element" which requires the TO and GO function within a company to treat each other as if they were unrelated entities and apply all of this standard's requirements.
Response: Thank you for your comment. **The drafting team revised the definition of Interconnected Element for clarity. INTERCONNECTED ELEMENT** **The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a**		

Organization	Yes or No	Question 2 Comment
summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.		
FirstEnergy	No	FirstEnergy supports the proposed definition for Protection System Study but believes the Interconnected Element definition requires some modification. As presently written the Interconnected Element definition appears to inadvertently omit coordination of two transmission owners that have tie-lines to each others systems. The two transmission owners are not "separate Functional Entities" but rather two Registered Entities performing the same functional entity (transmission owner) obligations. Additionally, it is understood that the intent is to also require Protection System coordination at interconnection points where the point of interconnection may entail facilities owned by the same NERC Registered Entity having multiple functional entity classifications. FirstEnergy proposes the following definition for Interconnected Element: "Interconnected Element - An Element that electrically joins and interconnects facilities owned by a)separate Registered Entities, or b) the same Registered Entity, but includes those representing multiple functional entity (DP, GO or TO) responsibilities."
Response: Thank you for your comments. **The definition of Interconnected Element has been revised based on your and others comments to read: INTERCONNECTED ELEMENT HERE**		
Hydro One Networks Inc.	No	For Protection System Study: Suggest adding a phrase:"A study between two or more interconnected power system Elements that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults".
Response: Thank you for your comments. **The drafting team believes the existing definition is sufficient.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td>Liberty Electric Power LLC</td><td>No</td><td>Functional entity is not defined. System Studies should be defined as "a study performed by a TO that demonstrates.....etc."</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
The definition of Interconnected Element has been revised based on your and others comments to read: INTERCONNECTED ELEMENT HERE
The drafting team believes the existing definition of a PSCS is sufficient and that both parties have responsibility to coordinate.</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>No</td><td>In the proposed definition of Interconnected Element “Functional Entities” is capitalized even though it is not in the NERC Glossary.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
The definition of Interconnected Element has been revised based on your And others comments to read: INTERCONNECTED ELEMENT HERE</td></tr>
<tr><td>SCE&G</td><td>No</td><td>SCE&G disagrees with the definition of “Interconnected Element”. More clarity is needed regarding the language “Functional Entities that are part of the same Registered Entity”. Entities that are vertically integrated and more specifically those vertically integrated companies that 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.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
The definition of Interconnected Element has been revised to provide more clarity based on your and others comments to read: INTERCONNECTED ELEMENT
The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.		
seattle city light	No	Seattle City Light does not agree with the use of Functional Entity in the definition of Interconnected Element. Seattle has several objections. First, although “Functional Entity” is capitalized in the draft Standard, this term is not defined in the NERC Glossary of Terms. A second objection is that “Functional Entity” in this role does not add clarity to the Standard. “Functional Entity” is defined in the NERC Reliability Functional Model as “the term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function.” This definition refers to other terms defined only with the Functional Model document (“Task,” “Function”). It is not illuminating as to defining the bodies joined by Elements. The third and strongest objection is that use of the term “Functional Entity” in the proposed definition is incorrect and inconsistent with the NERC Functional Model, and as such creates confusion about Standard obligations for entities registered for more than one function. The NERC Functional Mode Version 5 (November 30, 2009) explicitly does not require any particular organization or assignment of functional Tasks or ownership of Elements for any multi-function entity. Functional tasks and Elements exist undifferentiated across an entity as a whole, and the NERC Functional Model document states clearly that no further differentiation is expected, required, or implied. (See, for example, p. 7 “The Functional Model describes a functional entity envisioned to ensure that all of the Tasks related to its Function are performed. The Model, while using the term ‘functional entity’, is a guideline and cannot prescribe responsibility” and p.8 “The Model is independent of any particular organization or market structure.”) Seattle City Light, for example, is a vertically integrated municipal utility registered for 11 functions: BA, DP, GO, GOP, LSE, PC, PSE, RP, TO, TOP, and TP. Registration is made without differentiation: no particular sub-organization within Seattle City Light is identified as owning GO Elements, TO Elements, and

Organization	Yes or No	Question 2 Comment
		so on. The Model is simply that Seattle City Light or any other multi-function entity owns a set of Elements s a unit. By contrast the draft definition relies upon differentiation of ownership of Elements within a multi-function entity, so that it can be determined if the proper studies were undertaken or not. Such differentiation is outside the Model and introduces complexities and unintended consequences not envisioned by the Functional Model and the term "Functional Entity." The same confusion about the term Functional Entity occurs in draft Standard COM-003-1. Seattle suggests that NERC immediately clarify the use of this term. Until the definition of the Functional Model is changed and changed significantly, the use of Functional Entity to define obligations within a Standard or definition (other than in the Applicability section) should be eliminated. As is it is simply a misreading, tempting as it may be, to presume that Functional Entity Tasks are assigned with greater granularity than to an organization as a whole. And it is a misreading that does not promote high quality Standards that can be consistently enforced across auditors and across regions. You can do better, and should do better. Seattle apologies that it does not have a suggested fix at this time, because the Functional Entity approach is so fundamentally wrong. Entitly (entirely?) new wording would be required to capture Elements existing within the same registerd Entity.
Response: Thank you for your comment. **The definition of Interconnected Element has been revised based on your and others comments to read: INTERCONNECTED ELEMENT**		
JEA	No	Seems like Interconnect element is too broad and not enough clarity on what a protective system study requires (Ie, is this a setting coordination study? Redundancy studies? Dynamic studies? Duplication of TPL requirements.
Response: Thank you for your comment. **The definition of Interconnected Element has been revised to read: INTERCONNECTED ELEMENT**		

Organization	Yes or No	Question 2 Comment
The drafting team changed the name from Protection System Study to Protection System Coordination Study. **Note: The Guidelines and Technical Basis section of the Standard provides more information on the scope of a Protection System Coordination Study.**		
Imperial Irrigation District (IID)	No	Suggest replacing Protection System Study with Coordinated Protection System Study.
Response: Thank you for your comment. **The drafting team changed the name from Protection System Study to Protection System Coordination Study.**		
Certain Members of the ISO RTO Council	No	The definition of Interconnected Element is confusing since there are a mix of Functional Entities and Registered Entities, and some in the industry equate Functional Entities to Registered Entities. To avoid this confusion, we suggest replacing “Functional Entities” with “asset owners” or “facility owners.” If deemed desirable, the asset owners can be qualified by Transmission Owners, Generator Owners and Distribution Providers in parentheses The SRC asks if the definition for “Interconnected Facility” needs to be expanded to include situations where a Functional Entity may cross regional boundaries and have facilities that interconnect between the two, which may or may not be the same Registered Entity.
Response: Thank you for your comment. **The definition of Interconnected Element has been revised to read: INTERCONNECTED ELEMENT**		
Independent Electricity System Operator	No	The definition of Interconnected Element is confusion since there is a mixture of Functional Entities and Registered Entities, and some in the industry equate Functional Entities to Registered Entities. To avoid this confusion, we suggest to replace Functional Entities with asset owners or facility owners. If deemed desirable, the asset owners can be qualified by Transmission Owners, Generator Owners and Distribution Providers in parentheses

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment **The definition of Interconnected Element has been revised to read: INTERCONNECTED ELEMENT**		
Florida Municipal Power Agency	No	The definition of Interconnected Element limits the scope of the standard too much. The standard only requires coordination between neighboring entities and not of protection of other BES equipment within the same entity, e.g., one TO's transmission line protection with the protection of another transmission line owned by that same TO is not within the definition of Interconnected Element. It would seem that such a requirement would be necessary, e.g., each entity ensures that their protection internal to their system coordinates with itself, and that they coordinate at the boundaries with its neighbors. That would ensure coordination across the BES. Protection System Study definition should have a time element and a consideration for the critical clearing time, e.g., "and demonstrates that the resulting clearing time meets or beats the clearing time used in studies to comply with the TPL standards" or something to that effect
Response: Thank you for your comment. **The drafting team has no evidence that there is widespread miscoordination of Protection Systems associated the BES and therefore the necessity of ensuring that Protection Systems internal to an owner's system should not be included in this standard. However, the drafting team believes that the scope of the standard should require that the individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination at the Interconnected Element.**		
ITC	No	1. The general idea of the Interconnected Element is acceptable. However, when one Registered Entity takes care of coordination between two Functional Entities, or coordinates all protection coordination between the two systems, the documentation will become onerous and not enhance the reliability of the BES. 2. The definition of the Protection System Study still needs further clarification. It is not clear what calculations/documentation must be kept to properly demonstrate compliance with the requirement of a

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>“study.” Past practice may have kept calculations and correspondence, which adequately demonstrate “evidence of coordination,” but might or might not be adequate to a “protection system study” for future coordination efforts.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
1. **Just because the TO and GO are part of the same Registered Entity does not necessarily mean the same technical groups are involved in the required Protection System Coordination Studies. The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.**
2. **The standard only requires that a summary of the results of each Protection System Coordination Study performed be provided; as such this would be the item to retain**.</td></tr>
<tr><td>American Transmssion Company, LLC</td><td>No</td><td>The Interconnected Element definition should be expanded to clarify that PRC-027 is applicable to only BES Elements as demonstrated in Figure 4 of the Standard’s Application Guidelines on pg. 27.
o ATC recommends that the SDT please modify the definition of Interconnected Element as follows:”A Bulk Electric System Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity”
If “Functional Entity” is used and capitalized in the definition above, the term should be defined in the standard or be made part of the “Glossary of Terms Used in NERC Reliability Standards.” Furthermore, NERC’s “Reliability Functional Model version 5” states: “The following terms are used in the Functional Model and do not appear in the NERC Glossary. Functional Entity. The term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function.”</td></tr>
</table>

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<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment
The definition of Interconnected Element has been revised to read: INTERCONNECTED ELEMENT</td></tr>
<tr><td>Essential Power, LLC</td><td>No</td><td>1. The term Functional Entity needs a definition. It is capitalized in PRC-027 but is not defined in the standard or in the NERC Glossary. It is nonetheless evident that a GO and TO are different Functional Entities, but the nature of the Element that joins them and thereby constitutes the Interconnected Element is unclear. Is this the transmission line?
If so, would the TO be responsible for the R1 study if the ownership scope of an independent GO ends at the high-side terminals of the GSU or at an HV disconnect switch?
Would the responsibility be shared if, as sometimes happens, the ownership split occurs at the fenceline, leaving a small part of the transmission line the property of the GO while the rest belongs to the TO?
2.The definition of a Protection System Study needs to include identification of the party responsible for performing this work. This cannot be the GO if dealing with a deregulated market; since, as explained above, such parties are not allowed access to information about the TO’s system.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
1. The definition of Interconnected Element has been revised to read: INTERCONNECTED ELEMENT
2. The drafting team does not believe that the TO is restricted in providing the Protection System data necessary for the GO to ensure proper coordination of the protection systems covered by this proposed standard.</td></tr>
<tr><td>Cogentrix Energy Power Management, LLC</td><td>No</td><td>1.The term Functional Entity needs a definition. It is capitalized in PRC-027 but is not defined in the standard or in the NERC Glossary. It is nonetheless evident that a GO and TO are different Functional Entities, but the nature of the Element that joins them and thereby constitutes the Interconnected Element is unclear.</td></tr>
</table>

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<tr><td></td><td></td><td>Is this the transmission line?
If so, would the TO be responsible for the R1 study if the ownership scope of an independent GO ends at the high-side terminals of the GSU or at an HV disconnect switch?
Would the responsibility be shared if, as sometimes happens, the ownership split occurs at the fenceline, leaving a small part of the transmission line the property of the GO while the rest belongs to the TO?
2.The definition of a Protection System Study needs to include identification of the party responsible for performing this work. This cannot be the GO if dealing with a deregulated market; since, as explained above, such parties are not allowed access to information about the TO’s system.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comments.**
1. The definition of Interconnected Element has been revised to read: INTERCONNECTED ELEMENT
2. The drafting team does not believe that the TO is restricted in providing the Protection System data necessary for the GO to ensure proper coordination of the protection systems covered by this proposed standard.</td></tr>
<tr><td>GP Strategies</td><td>No</td><td>We do not believe that the drafting team appropriately identified the correct Applicable Functional Entities for this Standard. We also believe existing Standards could be modified to resolve any reliability gap rather than creating a new Standard. As a result, while the Purpose of this standard may seem to be reasonable, we feel that the drafting team should either
1) Change the Purpose to state “To conduct necessary studies to ensure Protection Systems for Interconnected Elements are studied, such that the least number or power system Elements are isolated to clear Faults.”
2) And change the Applicable Functional Entities to the Transmission Planner or modify existing Standards, instead, as described below. The short-circuit studies should be conducted by the Transmission Planner. From Appendix 5B of the Registration Criteria the:</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
		o Transmission Planner is the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area." o Distribution Provider is the entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage."TPL-001, TPL-002, and TPL-003 already require the system studies are conducted. These Standards should be modified to include any additional studies that the drafting team feels are a gap. As noted in the drafting teams Rational for Part R2.1 "Short circuit databases are customarily updated annually so the drafting team believes 24 months provides entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation." That being said, there is no current Requirement for the Distribution Provider to provide the information to the databases so that the Transmission Planner can conduct the studies on the Interconnection Facilities. We recommend that MOD-010 and MOD-012 should be modified to include the Distribution Provider instead. For new facilities, FAC-002-1 already requires the coordination of changes in the Facilities.

Response: Thank you for your comment.

1. **The drafting team revised the Purpose statement to: PURPOSE**
2. **The drafting team believes the applicability as noted is correct. Although is some cases, some of the identified activities may be conducted by the Transmission Planner or other entities, it is the Owners that are responsible for ensuring their Protection Systems are coordinated with others.**

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td>Public Service Enterprise Group</td><td>No</td><td>What information comprises a Protection System Study (PSS)? In the Application Guidelines, from Figure 1 on p. 24, each owner that receives a PSS is “to review the Protection System setting” associated with the other owner’s breaker that would operate to clear a Fault on the transmission line that connects each Interconnected Element. Is this (Protection System settings) the ONLY information that needs to be transmitted in a PSS by each owner? The SDT should itemize ALL of the information it believes needs to be included in a PSS that is to be transmitted between owners of an Interconnected Element and include that information in the examples in the Application Guideline. This information should also be listed into the PSS definition, thereby defining its scope.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
Requirement R1 section R 1.2 of the standard has been revised to state that after completion of each Protection System Coordination Study (PSCS) the owner performing the PSCS must provide “a summary of the results of each Protection System Coordination Study performed pursuant to this requirement, (including, at a minimum, the Protection Systems reviewed, any issues identified, and any revisions proposed).” Along with the Protection Systems reviewed, the drafting team believes that the minimum information that must be provided in a PSCS summary are the issues that were identified in the PSCS and any proposed revisions that were recommended as a result of the PSCS. Because most owners have their own unique Protection System setting philosophies and methods for performing a PSCS the drafting team believes providing a list of all the information that would comprise a PSCS would not be appropriate to include in Application Guidelines of this standard.</td></tr>
<tr><td>Tacoma Power</td><td>No</td><td>1.Where is the term Functional Entity defined?
2.Consider changing the term Protection System Study to Protection System Coordination Study. There are two reasons for this recommendation.
First, the abbreviation for Protection System Study is PSS, which is also the common abbreviation for power system stabilizer.
Second, the term Protection System Coordination Study emphasizes the primary</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
		purpose of PRC-027-1: to coordinate Protection Systems.
Response: Thank you for your comment. **1. The definition of Interconnected Element has been revised to read: INTERCONNECTED ELEMENT** **2. The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS).**		
Bonneville Power Administration	No	1.With regard to the definition of Interconnected Element, BPA believes the term should be interconnecting element, because the element is not interconnected, rather the systems of the functional entities are interconnected by the element. The point of interconnection between two functional entities is typically where two elements meet, such as between a line and a switch, and it is not a clear which element is the interconnected element. For example, suppose that a line from one entity terminates through a breaker at the bus of another entity's substation. Which is the interconnected element, the line, the breaker, or the bus? In another example, a generator ties to a transmission providers BES through a step-up transformer. Which is the interconnected element, the step-up transformer or the transmission line? Additionally, if a distribution provider taps off of a transmission provider's 230kV line through a disconnect switch, is the disconnect switch the interconnected element? BPA asks that the definition of Interconnecting Element be further clarified to provide the specific criteria that entities are expected to apply to come up with a consistent response in all such instances. The SDT attempted to illustrate the concept of the interconnected element through some examples in the Application Guidelines; however, the selection of the interconnected element in these examples neither follows logically from the standard nor provides the additional clarity necessary to enable industry participants to apply it in a manner that enables all users to come up with the same answers.. BPA believes

Organization	Yes or No	Question 2 Comment
		the standard needs a clearer definition of an interconnected element. 2.With regard to the definition of a protection system study, the definition given is too vague to provide a clear understanding of what is required by the standard.
Response: Thank you for your comments. **1. The drafting team has provided examples of the applicable Interconnected Elements in the Figures at the end of the standard. This standard applies to the Protection Systems associated with the Interconnected Element installed for the purpose of detecting Faults on BES Elements and that require coordination for isolating those faulted Elements.** **2. The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS) for clarity.**		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with question 2, we have the following general comments: (1) Please clarify why definitions are to remain with standard upon approval and not be moved to the Glossary. Are these definitions applicable only to this particular standard? If this is the case, this could lead to uncertainty if similar terms are going to be used or defined elsewhere. (2) Compliance 1.1 - The word 'Compliance' in the first line should not be capitalized and (CEA) should follow the word 'authority'. Since 'Regional Entity' is a defined term, 'Entity' needs to be capitalized. (3) Compliance 1.2 - The second paragraph should begin with 'Each', not 'The'. We suggest that the reference to an 'Interconnected Facility' in the second paragraph should be changed to 'a Facility associated with an Interconnected Element' to make it consistent with the rest of the standard, including the third paragraph of 1.2.
Response: Thank you for your comments. **1. Yes, the definitions are intended for use only in this standard.**		

Organization	Yes or No	Question 2 Comment
2. The noted corrections have been made. **3. The noted corrections have been made.**		
Texas Reliablity Entity	Yes	The SDT may want to consider additional language for the Protection System Study definition, to clarify that the study demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults as well as clear the Faults within the maximum time frame defined by the Transmission Planner in order to maintain System Stability. Another consideration would be that the study incorporates all of the applicable Fault contingencies (Category B and C) as defined in the NERC Reliability Standards (TPL-002 and TPL-003) or any Regional standards.
Response: Thank you for your comments **The drafting team believes the definition as stated is sufficient.**		
Duke Energy	Yes	The SDT should consider putting the definition of Interconnected Element in the NERC Glossary.
Response: Thank you for your comment; **The drafting team intends for this definition to be used only with this standard.**		
Southwest Power Pool Reliability Standards Development Team	Yes	1. Under figure 2 in the application guidelines the example need to be reviewed and text added to clearly identify the intent of the drafting team. For example is the scope for Generator Owners in figure 2 just the backup system protection for the Transmission Owners system? It's not clear in the examples given. This issue is also present in figure 5. We agree that if the scope is just for the backup system protection it is ok but the wording does not clearly state this. 2. Also using PSS as an acronym for Protection System Study could be confused in the flowchart of this standard with power system stabilizers

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<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>since there isn’t any text to spell out that it is referring to Protection System Study.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
1. The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.
2. The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS) for clarity.</td></tr>
<tr><td>Western Electricity Coordinating Council</td><td>Yes</td><td>We agree with the definitions, but question the appropriateness of development of terms for a specific standard. Individual Regions are strongly discouraged from defining terms that only apply in a single region. We see the development of a term that is only applicable to a single standard to be a similar situation, leading to a proliferation of terms. If this approach is acceptable to NERC and FERC, we have no concerns.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
This approach is consistent with NERC standard drafting guidelines.</td></tr>
<tr><td>Pepco Holdings Inc & Affiliates</td><td>Yes</td><td></td></tr>
<tr><td>Western Small Entity Comment Group</td><td>Yes</td><td></td></tr>
<tr><td>Midwest Reliability Organization NERC Standards Review Forum</td><td>Yes</td><td></td></tr>
<tr><td>National Grid and Niagara Mohawk (A National Grid Company)</td><td>Yes</td><td></td></tr>
<tr><td>Luminant</td><td>Yes</td><td></td></tr>
</table>

Organization	Yes or No	Question 2 Comment
Dominion	Yes	
SERC Protection and Controls Subcommittee (PCS	Yes	
Tennessee Valley Authority	Yes	
US Bureau of Reclamation	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	
pacificorp	Yes	
Southern Company	Yes	
Dynegy	Yes	
Ingleside Cogeneration LP	Yes	
Wisconsin Electric Power Company	Yes	
Ameren	Yes	
Entergy Services, Inc. (Transmission)	Yes	
City of Austin dba Austin Energy	Yes	
Idaho Power Co.	Yes	
Nebraska Public Power District	Yes	

Organization	Yes or No	Question 2 Comment
Georgia Transmission Corporation	Yes	
Xcel Energy	Yes	
City of Tallahassee	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: Response: Thank you for your support. **Al M to review and provide answer**		

3. **In Requirement R1, the drafting team modified the time frame to allow entities 48 months to have a documented Protection System Study completed for each Interconnected Element if no Protection System Study exists. Note, the drafting team has allowed inclusion of all previously performed Protection System Studies whose summary of results include, at a minimum, the protective relay settings reviewed, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Quick summary: 36 no with comments- 15 or so requested more time

5 yes with comments

17 yes with no comments

Discussion Points:

Go to 60 months

Should it be part of requirement or move to implementation plan?

Organization	Yes or No	Question 3 Comment
Kansas City Power & Light	No	1. Proposed Requirement R1 allows 48 months to do an initial study with the explanation that there is no evidence of widespread miscoordination. We agree that there is no evidence of widespread miscoordination and therefore 60 months is the proper time frame for an initial study. 2. We have also noticed that there is no question on this comment form for any other comments not addressed by the drafting teams questions. As such we note here that Requirement R1, 1.1.2 lists a 10% change in current as an action point. This implies that a 10% decrease requires action. We do not agree with this since most Protection Studies are done with all generation on. Most of the year all generation is not on with the result that normal operating conditions

Organization	Yes or No	Question 3 Comment
		result in fault currents that are 10% below the maximum used in the Protection System Study. We also disagree with action required for a 10% increase in fault current since our standard relay settings no longer trip for instantaneous ground over current elements and the standard does not allow an entity to state a reason not to run this study or perform the calculations. When we did utilize instantaneous ground over current elements we allowed a 40% margin. We utilize other high speed protection elements not directly affected by changes in fault current. We recommend at least a 20% change in fault current to require action per this standard. 3. Requirement R2 requires that a short circuit study be done every 24 months. As noted above 60 months is proper time for initial study and is also proper for subsequent studies done after the initial study is complete.
Response: Thank you for your comment. 1. Based on stakeholder comments, the drafting team revised the timeframe for Requirement R1, Part 1.1.1 to 60 months. 2. The drafting team believes, as noted in the rationale, that the ±10 % change is an appropriate threshold to trigger investigation of the need for a review of Protection Systems. This does not require a new Protection System Coordination Study if an entity provides a technical justification demonstrating why a new study is not necessary. 3. The drafting team revised Requirement R2 to require, at least once every 60 months, Transmission Owners perform a short circuit study and calculation of fault current deviation for its Interconnected Elements or provide a technical justification why periodic fault current studies are not necessary for the coordination of Protection Systems associated with Interconnected Elements.		
ACES Standards Collaborators	No	(1) While we do not disagree with the time frame, we question if it should be part of the requirement. It makes more sense to include the time frame for initial compliance of a requirement in the implementation plan. In that way, the initial compliance time frame does not persist in the standard long after it is no longer needed. It is common to utilize the implementation plan to describe initial compliance dates, especially when the requirement is asking for documented studies. After the studies are complete, there is not a need for a

Organization	Yes or No	Question 3 Comment
		timeframe. Furthermore, FERC approves implementation plans as part of the standards package so there is no issue with whether the implementation plan is enforceable. (2) Conceptually, we agree with the intent of the standard and this requirement as it is presented in the application guidelines. However, more refinement is needed to make this requirement mirror what is explained in the application guidelines. For instance, we recommend clearly stating in Requirement R1 that the responsible entity is only responsible for performing Protection System Studies (PSS) for only those breakers it owns and are protecting the Interconnection Element. The standard is close to capturing this intent with the statement “its System” in Part 1.1. It would be better it if was changed to “Perform a Protection System Study for each of its Protection Systems that are protecting an Interconnected Element.” A GO and DP do not really have systems so the current language is not appropriate for these functions. The application guidelines provide this clarity and would be helpful if the intent was clearly stated in the requirements.
Response: Thank you for your comment. 1. **The drafting team agrees your suggestion provides one way of addressing initial requirements to have documented Protections System Coordination Studies for each Interconnected Element. However, the drafting team believes the current structure of Requirement R1, Part 1.1.1., as currently written, achieves this same goal. Further, NERC performs periodic review of standards and the requirement can be removed at that time, if appropriate.** 2. **Based on your suggestion, the drafting team has modified the language of the requirement to read: “Perform a Protection System Coordination Study for each of its Interconnected Elements…”.**		
CenterPoint Energy	No	(a) CenterPoint Energy continues to believe a requirement to have a documented Protection System Study for each existing Interconnected Facility is overly burdensome, unless certain - if not all - existing Interconnected Facilities are exempted; therefore, CenterPoint Energy recommends R1.1.1 be eliminated from PRC-027-1. CenterPoint Energy does not believe a reliability need has been

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>identified to justify that such prescriptive requirements are needed to provide for an adequate level of reliability. The following is stated on page 18 of 28 in PRC-027-1 Draft 2: “records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” The majority of existing Interconnected Facilities have fault-proven, time-proven protection system set points. An existing Interconnected Facility without a documented Protection System Study will eventually be included in a study with system additions and changes, short circuit current increases, and relay panel replacement projects, as well as any analysis of misoperations.
(b) While an option has been included in Draft 2 R1.1.3 to allow for a technical justification why a study is not required for certain changes, CenterPoint Energy believes that reasonable thresholds should be established for the changes identified in R3.1. For example, R3.1 requires that “any” change of sequence or mutual coupling impedance must be provided to a Generator Owner. For insignificant changes of sequence or mutual coupling impedance, CenterPoint Energy believes there would be little, if any, reliability benefit of communicating and technically justifying why a study is not required.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
a) The drafting team believes that there is a reliability benefit in ensuring that all existing Protection Systems on Interconnected Elements have been reviewed. The drafting team acknowledges the fact that no immediate reliability concern has been identified and, as such, has allocated an extended time to complete this work.
b) The drafting team believes that information about any change (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 Element.</td></tr>
<tr><td>FirstEnergy</td><td>No</td><td>A) FirstEnergy supports the 48 month timeframe to complete initial Protection System Studies. However, based on the fact that the drafting team may have overlooked system tie points of two transmission systems (see our response to</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		Q2) the completion of Protection Studies may require additional time. B) FE could support a 48 month implementation and encourages the drafting team to consider a staggered plan that requires earlier completion for higher voltage systems. For example, 1) systems operated at 300kV and higher within 24 months, 2) systems operated at 200kV and higher up to 300kV within 36 months and 3) systems operated at 100kV and higher up to 200kV within 48 months. C) As expressed in FirstEnergy's Draft 1 comments, we do not support requirement text that is better placed in an Implementation Plan. A requirement should be written such that it is everlasting. As written, R1 part 1.1.1. has no meaning after the 48 month period expires. D) It is FirstEnergy's experience that the Transmission Owner would likely have the expertise and staff to perform the desired Protection System Study. The team should consider whether or not the DP and GO would typically be performing their own independent study or collaborating with the TO in a supporting role by providing data and reviewing study results. In regard to items B) and C) FirstEnergy proposes the following for Requirement R1. **Start of proposed requirement R1 text **R1. Each Transmission Owner shall perform a Protection System Study for each Interconnected Element on its System associated with a Generator Owner, Distribution Provider or another Transmission Owner. Each study shall include at a minimum: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning] - the protective relay settings reviewed - power system Elements to be isolated - contingencies evaluated - Fault currents used - any issues identified - any revisions proposed 1.1. Each Transmission Owner shall update its Protection System Study: 1.1.1 Within six calendar months after determining or being notified of a 10% or

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required.
1.1.2 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 Part 3.3, or technically justify why such a study is not required.
1.2. Within 90 calendar days after the completion of each Protection System Study the Transmission Owner shall provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement.**End of proposed requirement R1 text **
E) FirstEnergy recommends that for ease of ordered reading that the numbering of Measures be tied to the Requirement number. For example Requirement R1 has two measures M1 and M2. Consider renumbering to M1.1 and M1.2.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
A) The drafting team does not agree that it has overlooked the Transmission Owner to Transmission Owner interconnections in the Interconnected Element definition. However, it has been modified as follows: INTERCONNECTED ELEMENTS HERE.
B) Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months. The drafting team chose not to prescribe how an entity achieves compliance with this requirement; however, an entity may implement its own phased in approach within the confines of a 60-month maximum time frame.
C) The drafting team agrees your suggestion provides one way of addressing initial requirements to have documented Protections System Coordination Studies for each Interconnected Element. However, the drafting team believes the current structure of Requirement R1, Part 1.1.1., as currently written, achieves this same goal. Further, NERC performs periodic review of standards and the requirement can be removed at that time, if appropriate.
D) The drafting team recognizes that in many cases the Protection System Coordination Study may be a collaborated effort; but, ultimately it is the owner’s responsibility.
E) The format used in this Standard is consistent with the current NERC standards development process.</td></tr>
<tr><td>Sacramento Municipal Utility District</td><td>No</td><td>“The results based objective is that the registered entities communicate and</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		coordinate with each other. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard is met." Performance of a PSS is an intermediate step toward achieving coordination. It does not improve reliability if an entity does not act on it. Only in the final step - when agreed upon changes are made - does system reliability actually improve. The standard should consist of R3.1 (one side makes a change which triggers a review), followed by R4.2 (all parties agree to the changes to be implemented). Documenting the process steps between these two points in time does not improve system reliability.
Response: Thank you for your comment. **The drafting team believes all Requirements included in this standard support its reliability objective.**		
American Electric Power	No	AEP believes that 48 months to complete a Protection System Study is too short of a time frame, especially for Interconnected Elements which do not have an existing study. NERC's rationale for R1 states that "the drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame." If this is the case, then there should be no issue with extending this timeframe. AEP believes that 72 months is a more reasonable timeframe for the following reasons: * The Transmission Owner will need to complete their own studies, as well as provide data to the entities they interconnect with (i.e. TO's, GO's, and DP's). This dependency would effectively shorten the amount of time the functional entity has to complete their studies to less than 48 months. * Before the work of the first bullet point above can be completed, entities must develop an agreed-upon list of Interconnected Elements and associated owners of the Protections System(s) associated with each Element. Once again, the time required to complete this task erodes into the entire time allowed to perform the study. In short, much of this work must be sequentially rather than in

Organization	Yes or No	Question 3 Comment
		parallel, further justifying the need for an increased timeframe. * The resources needed to complete the required studies will also be impacted by a number of other standards currently in draft including: PRC-006-1, PRC-019-1, PRC-024-1, PRC-025-1 and PRC-004-3. The work required to perform both the proposed studies of this standard, as well as the other standards listed above, requires a Subject Matter Expert possessing a specific skillset gained from years of protection experience. Due to the limited number of such SMEs, industry will be very challenged in meeting all the proposed requirements given the limited number of such resources. In addition, the demand for qualified outside resources might be greater than their actual availability due to the time constraints involved.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team revised the timeframe for Requirement R1, Part 1.1.1 to 60 months.**		
Salt River Project	No	Agree with timing, but confirmation from both parties that coordination has been reviewed should be adequate evidence.
Response: Thank you for your comment. **The Standard as stated only requires that the respective Owners confirm acceptance of the proposed changes.**		
Florida Municipal Power Agency	No	As worded, R1 seems to require two neighboring entities to perform independent studies. We would hope that the intent of the drafting team is to allow any one entity to do a study and then the neighboring entity accept the results of that study, or to perform a joint study. We suggest the drafting team make conforming changes to allow this.
Response: Thank you for your comment. **The drafting team recognizes that in many cases the owners may do joint studies; but both entities would need to agree with the results of the Protection System Coordination Study. After the initial assessment, the Transmission Owner is the entity required to**		

Organization	Yes or No	Question 3 Comment
perform future, periodic fault current studies. **It is also recognized that, in most cases, it will require a collaborative effort to complete the studies; but ultimately, it is the owners' responsibility to ensure that the requirements of this standard are met.**		
ATCO Electric	No	ATCO Electric (AE) has an existing protection review program that runs on 5 year cycle. Each year, AE review approximately 20% of AE's transmission system to ensure the protection is in place or needs adjustment. Can the drafting team increase 48 month duration to 60 months?
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.**		
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.
Response: Thank you for your comment. **The drafting team believes that there is a reliability benefit in ensuring that all existing Protection Systems on Interconnected Elements have been reviewed. The drafting team acknowledges the fact that no immediate reliability concern has been identified and as such has allocated an extended time to complete this work.**		
Luminant	No	Comment on Requirement R1.2. The time frame listed may not be adequate under all circumstances or situations. Luminant recommends that the language be changed in this requirement as follows: "... Protection System Study performed pursuant to this requirement (including at a minimum, the Protection System(s) reviewed, any issued identified, and any revisions proposed) shall be within 90 days or in accordance to an agreed-upon schedule with a Transmission Owner, Generation Owner, or Distribution Provider." This would align with R4.1 that also provides the same time frame. The corresponding measures will also need to be modified if this language is accepted.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. **Requirement R1, Part 1.2 requires entities to provide a summary of results of a Protection System Coordination Study (PSCS) to affected entities within 90 days of completion of such a study. Requirement R4, Part 4.1 provides an additional 90 days (or according to an agreed upon schedule) for the recipient of the summary results to review and respond. Considering the 90-day time frame begins after the completion of a PSCS, and only addresses the amount of time allotted to provide a summary of the study to another entity, the drafting team believes there is no need to add the caveat of "an agreed upon schedule" to the 90-day time limit.**		
Western Electricity Coordinating Council	No	Creating a Protection System consists of conducting Protection System studies and incorporating the data into an entity's transmission/generation/distribution system. Protection System studies are not a new concept to entities. In the event that an entity discovers that certain interconnected elements are not included in the Protection System study the entity should not require 48 months to make the needed changes to the study. From a reliability perspective, entities should already have a basic Protection System study in order to have a Protection System. Allowing an additional 48 months creates a potentially large 4 year reliability gap based on entities existing studies and any needed corrections. From a compliance perspective, allowing a 48 month time frame for entities to have a documented Protection System study effectively pushes mandatory compliance for this standard out for an additional four years beyond the effective date. This time frame is excessive and should be reduced to no more than 24 months from the effective date of the standard.
Response: Thank you for your comment. **Based on stakeholder comments, and recognizing there is no evidence of widespread miscoordination of Protection Systems associated with Interconnected Elements, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.**		

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	Due to the extensive documentation, coupled with the collaboration between entities associated with this requirement, NPCC believes 60 months is a more appropriate time frame to comply. This timeframe is also more in line with the timeframe proposed in the draft PRC-019-1 in Project 2007-09. An alternative to the "static" time frame discussed above, which would also be acceptable, would be to base the timeframe on a formula that factors in the number of interconnected power system elements that the entity must contend with.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.**		
Pepco Holdings Inc & Affiliates	No	Each owner should already possess information demonstrating that their protective devices are set to “coordinate” with adjacent protection systems. However, the documentation that presently exists may not be in the form of a formal “coordination study” in a format suitable for audit purposes. Some guidance should be provided indicating what form of documentation is expected, especially by the TO. For instance, on transmission tie lines between different TO’s coordination of zone distance elements is fairly straightforward and can be accomplished without a traditional “coordination study”. Also settings on pilot schemes need to be exchanged in order to allow for proper operation, but this is also not what is considered a traditional “coordination study”. On the other hand, coordination between GO’s and TO’s is even more complicated. Without some direction as to what specific documentation is required it is difficult to estimate how many existing interconnection points would have to be re-visited in order to produce the required auditable documentation. Some specific examples of what specific type of documentation is required would be helpful. To be safe, most likely all interconnection points would be revisited to ensure adequate compliance documentation. Also, for each revised Protection Study produced (per R1.1) a

Organization	Yes or No	Question 3 Comment
		formal review (R1.2) and approval (R4.1) would be required. As such, with the large number of interconnection points on the system a 60 month time frame would be more appropriate. The drafting team acknowledged that they had no evidence that there is widespread miscoordination between Interconnected Facilities when establishing the arbitrary 48 month requirement.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.** **Note: Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS.**		
Southern Company	No	For large entities with hundreds of generators, a longer initial time frame is needed. In addition, consideration should be given to the fact that existing transmission protection and control engineering personnel will be fully engaged in the work associated with FERC order 754 for The next 12+ months.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.**		
Georgia Transmission Corporation	No	Guidelines and Technical Basis Req. R1: "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."......These studies may include graphical coordination....; relay scheme simulation studies....; and sensitivity studies using sequence...., and adequate directional polarizing quantities. This activity will be onerous without a full system model and software to perform studies that would check coordination of stacked curves and stepped distance relays. Of particular note is the question of adequate directional polarizing quantities. There should be an expected minimum requirement such as time overcurrent plots and zone distance plots of the existing relay settings

Organization	Yes or No	Question 3 Comment
		for the terminal with the fault points used as the basis. This data would then be used to indicate if the 10% point has been reached that would require a new coordination follow up at the end of the next 24 month fault study.
Response: Thank you for your comment. **Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS. The ±10% threshold relates to the fault current at the interconnected bus; not individual relay tolerances.**		
National Grid and Niagara Mohawk (A National Grid Company)	No	How would "fault currents used" be presented for coordination of distance relays ? Also if the above items must be included, at a minimum, they need to be enumerated in requirement R1.
Response: Thank you for your comment. **Each company must determine proper use of fault currents for their particular Protection System components. The language of the Requirement R1, Part 1.2 has been modified to indicate "(including, at a minimum, the Protection Systems reviewed, the associated fault currents used, any issues identified, and any revisions proposed)".**		
Hydro One Networks Inc.	No	Hydro One believes 60 months is a more appropriate time frame to conduct, document and obtain consensus for a protection system study. This timeframe is also more in line with the timeframe proposed in the draft PRC-019-1 in Project 2007-09. Large entities and small entities have the same time frame to complete this work which seems unreasonable. Alternatively, an extended period should be provided based on a formula that factors the quantity of interconnected power system elements.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.**		

Organization	Yes or No	Question 3 Comment
Ingleside Cogeneration LP	No	Ingleside Cogeneration, like many other Generator Owners, does not typically perform fault studies unless we have made material changes to our transmission system interconnection. Even then, we provide modeling data to the appropriate Transmission Owners and Transmission Planners, who execute the assessments on a Regionally-standardized platform. We are not convinced that we can add value to this process - other than to demonstrate that the information required by the TO and TP was provided, and the study took place. In our view, the requirement should clearly accommodate this working arrangement. As it reads now, it seems like both the GO and the TO must perform separate assessments. The extra costs that we will incur to commission external consultants is difficult to justify when there are so many other pressing priorities (e.g.; cold weather preparedness).
Response: Thank you for your comment. **The drafting team recognizes that in many cases the owners may do joint studies; but both entities would need to agree with the results of the Protection System Coordination Study. After the initial assessment, the Transmission Owner is the entity required to perform future, periodic fault current studies.** **It is also recognized that, in most cases, it will require a collaborative effort to complete the studies; but ultimately, it is the owners' responsibility to ensure that the requirements of this standard are met.**		
Dynegy	No	Perhaps R1 could be reworded to answer the following question: "If an entity registered only as a GO owns relays that trip the generator alone (and not relays detecting a fault on any transmission lines), does this Standard apply?"
Response: Thank you for your comment. **Per the Applicability section of the standard, if the Generator Owner owns no Protection Systems that require coordination with other owners, then the standard would not apply to those Protection Systems.**		
Portland General Electric Co	No	Portland General Electric Company appreciates the drafting team's consideration

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>of comments. Since there wasn't a general comment section at the end of this form, the discussion of timeframes seems appropriate here.
The effective date (the first quarter six months after approval) does not allow sufficient time for compliance. This standard will require that entities include in all interconnection agreements a detailed protection coordination schedule or be subject to the long timelines detailed in the standard. None of the agreements (if they even exist) for projects six months out include a protection coordination schedule, nor do their project schedules accommodate the long durations detailed in the standard. Agreements will also need to be drawn up for smaller projects in order to document a protection coordination schedule, lest the interconnecting utility prevents us from energizing by taking the full 90 days to review the relay settings. In addition, entities may need at least one additional resource to conduct the bi-annual coordination studies and manage the interconnection due dates. PGE suggests an implementation period of 24 months since planning is done more than a year in advance.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes the elements of Requirement R3 provide sufficient flexibility for project scheduling with regard to achieving proper Protection System Coordination prior to energization.
Based on stakeholder comments, the drafting team has extended the timeframe for Requirement R1, Part 1.1.1 and the periodic fault current study to 60 months.</td></tr>
<tr><td>Liberty Electric Power LLC</td><td>No</td><td>R1 should not apply to GOs. GOs are not allowed to have the TO information needed for a system study under market rules.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team does not believe that the Transmission Owner is restricted from providing the Protection System data necessary for the Generator Owner to ensure proper coordination of Protection Systems applicable to this proposed standard.</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
ReliabilityFirst	No	ReliabilityFirst abstains and offers the following comments for consideration: 1. Requirement R1, Part 1.1.1a. ReliabilityFirst questions the rationale for the 48 calendar month window to perform a Protection System Study if NO study exists. ReliabilityFirst believes that a Protection System Study is one of the fundamental reasons for the standard and believes if NO study had ever been performed, one should be performed as soon as possible (12 months). Within the rationale section, the drafting team states: "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame." With no widespread mis-coordination of protection systems, ReliabilityFirst questions the actual need for the standard itself. 2. It is not clear where the 10% threshold in Part 1.1.2 and calculated in Part 2.1.2 is applied. Does the 10% threshold apply to the total bus Fault current at the interconnecting bus or the contributing Elements? If it is the total, then there are situations where some of the sources into the bus may change their contribution quite a bit more than the 10% threshold but yet the total change could be less than 10%. Protective relaying is set in reference to the Element it is protecting or, to be more precise, the instrument transformers associated with an Element. The 10% threshold should be applied to the Interconnecting Element as its contributing quantities could change significantly even if the total Fault current stayed nearly the same. It is the Fault quantities on the Element that the interconnection protection sees - not the total bus Fault current (unless the Interconnecting Element is a bus). It is also not clear which phase or sequence currents are being used in the %Deviation calculation. Is it 3I0 (3 times zero sequence) current for single line to ground Faults and I1 (positive sequence) current for 3-phase Faults? It should be noted that if variations in Fault current of 10% are acceptable, then entities may need to adjust their criteria to use margins of 15% or more to consider other sources of error such as relay and instrument transformer accuracy.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months. Additionally, the drafting team believes there is a reliability benefit to require that all interconnected Elements have a valid Protection System Coordination Study in order to ensure coordination between owners of interconnected Elements.
2. Requirement R2, Part 2.1.1 refers to maximum available current at the interconnecting bus (total bus fault current). The drafting team has included clarifying language in the Rationale for Requirement R2, Part 2.1 and in the language of Requirement R2, Part 2.1.2 to indicate the need to compare both line-to-ground and three-phase fault current values when performing the calculation to check for a ±10% deviation.</td></tr>
<tr><td>Entergy Services, Inc. (Transmission)</td><td>No</td><td>Request consideration in replacing the time increment of 48 months with 4 years for the time frame.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team has retained the use of months; however, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.</td></tr>
<tr><td>PPL Corporation NERC Registered Affiliates</td><td>No</td><td>Sixty months would be more appropriate to study all the interconnections. There has not been a major problem with mis-coordination of Protection Systems associated with Interconnected Elements. Also, the standard does not fully address what all should be included in a Protection System Study.R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.</td></tr>
<tr><td>ITC</td><td>No</td><td>The amount of work required to comply with this requirement may be significant and may impact ongoing efforts to upgrade and improve the system. The above items that need to be documented can often be discussed and agreed to verbally between parties and are were often not part of a permanent record.</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		The additional record keeping required may be significant and not add to the reliability of the BES.

Response: Thank you for your comment.

The drafting team does not believe a verbal agreement is measurable or auditable.

Organization	Yes or No	Question 3 Comment
Western Small Entity Comment Group	No	The comment group agrees that Protection Systems associated with Interconnected Elements must be coordinated. However, the reliability goal should be strictly focused on documenting the associated owners (parties) are cooperating, and in agreement with protection settings to achieve proper coordination. A requirement to have a documented Protection System Study completed will not improve on a simple statement from the parties that proper coordination has been agreed upon. Provision of a Protection System Study as compliance evidence (in whole or a summary) implies recourse to check its completeness or accuracy. For complex systems, this is very subjective. However, the Standard as written intends to make no effort to verify the completeness or accuracy of a Protection System Study; the intent is to simply verify that it exists. Since the Protection System Study is not subject to review, its production as compliance evidence is nothing more than added bulk.

Response: Thank you for your comment.

Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS. Minimum elements required in the summary results are provided in Requirement R1, Part 1.2. It is the responsibility of the respective owners to ensure the accuracy and completeness of the study results.

Organization	Yes or No	Question 3 Comment
Public Service Enterprise Group	No	The issue is consistency in what comprises a valid PSS. For example, for "contingencies evaluated," it seems that each owner should evaluate a core set of the same contingencies as opposed to this being an owner-by-owner decision. The lack of specificity as to what is required for a PSS is the issue.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.
A Protection System Coordination Study (PSCS), by definition within PRC-027, must demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults. Most entities have internal procedures regarding the performance of coordination studies that produce the results required, but may not involve the exact same process or procedures that another entity follows to achieve Protection System coordination. The drafting team chose not to specifically dictate the elements of this process, but rather to continue to allow entities to “demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults” according to their own internal procedures.
The examples of information required in a “summary” of the results of a PSCS represent a minimum set of data that must be provided so the receiving entity can effectively assess coordination of the system. The drafting team has revised the examples to add clarity and the particular example provided in your comment has been removed.</td></tr>
<tr><td>Midwest Reliability Organization NERC Standards Review Forum</td><td>No</td><td>The NSRF recommends that this Standard be filtered through the paragraph 81 criteria. If not, the NSRF recommends the following items.
1. Although supportive of the extended timeframe in R1, the NSRF is concerned that the proposed Part 1.2 is overly prescriptive. Considering the sheer quantity of microprocessor relay settings that could potentially be reviewed as part of a Protection System Study, having to provide associated owner(s) the results of every protective relay setting reviewed would be unnecessarily burdensome with little benefit to reliability. Recommend the drafting team revise Part 1.2 to require entities to only provide information related to settings being proposed for change and have all other settings be made available upon request.
2. Please clarify the application of R1, Part 1.2 in the event that both ends of the Interconnected Element are owned by the same entity. In consideration that final settings and internal documentation would provide proof that everything was looked at accordingly, would the entity still need to develop and distribute a summary internally as well? Recommend revising Part 1.2 to only require functionally separate entities to provide documentation of the results of the Protection System</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		Study. 3. Rather than specify the details to be shared as a result of a Protection System Study, recommend Part 1.2 be modified to remove "power system Elements to be isolated, contingencies evaluated" as a minimum requirement. Having entities share their evaluation methods with other Entities appears to be unnecessary administrative work. Considering that it is the responsibility of the individual entity to perform their studies correctly, another entity should not have to worry about, nor does it have the responsibility for keeping tabs on, whether an external study was done to a single or double contingency level, what external Facilities become isolated, etc. Additionally, the NSRF is concerned with the phrase "Fault current used" as it applies to R1, Part 1.2. In consideration that Fault current values do not necessarily mean that two entities are using like models, recommend a comparison of boundary equivalents be used instead to ensure that the models are comparable between entities. If not, entities would potentially be sharing every value for every iteration to ensure like models. Suggested revisions to R1, Part 1.2 in support of the above comments are as follows: 1.2. Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with Interconnected Element(s) that include two or more Registered Entities, a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, proposed revisions to the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, boundary equivalents at necessary buses Fault currents used, any issues identified, and any additional revisions proposed). If existing documentation does not include enough detail to meet the requirement for an acceptable Protection System Study, utilities will be forced to

Organization	Yes or No	Question 3 Comment
		add to the existing documentation for compliance purposes even though the existing settings coordination is adequate. This will place additional compliance burden on utilities while not necessarily improving reliability. Since there is no evidence of widespread mis-coordination of Protection Systems associated with Interconnection Elements, it would seem reasonable to have this standard apply to any changes made to an existing Protection System or all new Protection Systems.
Response: Thank you for your comment. **1. In response to stakeholder comments, the drafting team has refined the examples given in Requirement R1, Part 1.2 of the minimum information required in a summary of the results of a Protection System Coordination Study (PSCS).** **2. The drafting team believes, even for functional entities under the umbrella of a single company, there is a reliability benefit associated with the provision for the information required in a summary of results of a PSCS from Transmission Owner to Generator Owner. The drafting team does acknowledge that in the cases where a single person is doing the overall coordination for a given interconnection; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study should be sufficient for use by both owners.** **3. In response to stakeholder comments, the drafting team has refined the examples given in Requirement R1, Part 1.2 of the minimum information required in a summary of the results of a Protection System Coordination Study. The particular items you mentioned were removed from the requirement.**		
American Transmssion Company, LLC	No	The drafting team states that there is no evidence of wide spread misoperation due to lack of coordination. However, R1 requires a utility to establish an evidence package of legacy coordination that predates PRC-001's effective date. While 48 months is an improvement to PRC-027, that timeframe still imposes a significant burden on utilities, especially those that are not vertically integrated. ATC recommends that the drafting team consider changing the implementation period for R1 from 48 months to 72 months.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>Essential Power, LLC</td><td>No</td><td>The time frame is not the issue. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that the Generator Owner is an appropriate Applicable Entity for this Standard since they often apply Protection Systems that require coordination with other owners' Protection Systems.</td></tr>
<tr><td>Cogentrix Energy Power Management, LLC</td><td>No</td><td>The time frame is not the issue. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that the Generator Owner is an appropriate Applicable Entity for this Standard since they often apply Protection Systems that require coordination with other owners' Protection Systems.</td></tr>
<tr><td>Nebraska Public Power District</td><td>No</td><td>To mitigate compliance risks for various types of data formats for existing studies and studies older than June 2007 this standard will likely require utilities to go back and update all data so that it meets the requirements and description of evidence in the application guidelines when the requirements become enforceable. This could likely take longer than 3 years. I would recommend more time such as 6 years based on two audit periods (time depends on the number of applicable system ties as well).</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.</td></tr>
<tr><td>Southwest Power Pool Reliability Standards Development Team</td><td>No</td><td>We are concerned that 48 months could still not be sufficient for these studies. We would ask that the team consider 72 months. There is a concern that with all the companies having new standards to comply with, the Transmission</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>Owners/Generation Owners are being overloaded and have the same resources.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.</td></tr>
<tr><td>Tennessee Valley Authority</td><td>No</td><td>We do not feel like 48 months is a reasonable timeframe to meet the minimum requirements for Protection System Studies (PSS). In the current form of the standard, for an existing PSS to be valid, several minimum requirements are given in R1.2. While this is a good requirement for new PSS, it eliminates almost all of our existing PSS as being valid. We have the stance that many of our existing PSS are of a high quality and should be considered valid, but do not meet the minimum requirements from R1.2. We recommend allowing existing PSS to be submitted in their current form between all protection system owners of an Interconnected Element within a reasonable time frame of the standard effective date and allowing the owners to approve the existing PSS as valid if they desire. Then, that existing PSS could be used as the baseline PSS until the 10% change in fault occurs from the existing dated PSS. At that time, a new PSS should be performed to meet the minimum requirements as outlined in R1.2.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team recognizes that entities approach the process of protection system coordination according to individual entity policy and procedure, yet still achieve the same high quality results in the end. Based on your and others' comments, the drafting team has modified the timeframe associated with Requirement R1, Part 1.1.1 to 60 months and revised the minimum information required in a summary of the results of a Protection System Coordination Study.
The issue here is a previous study that wasn't document to the level of R1.2
If you have an old study: can you put together a summary that includes all the needed information and send it to the other party to review after the effective date of the standard?</td></tr>
<tr><td>Wisconsin Electric Power Company</td><td>No</td><td>1.We strongly believe that 60 months would be a more achievable time frame to</td></tr>
</table>

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<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>study the many interconnections that an entity may have. This will also allow Generator Owners the time needed to gain the resources required to perform these studies, since they may not be presently so equipped. As stated by the drafting team in the rationale for R1 there is no evidence of wide spread mis-coordination of Protection Systems associated with Interconnected Elements.
2.It would also be helpful to provide a better description of what is required to be included in a Protection System Study. For example, is the study required to include pilot scheme timing and element coordination, breaker failure coordination, coordination under minimum and maximum fault current cases, etc?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 months.
2. A Protection System Coordination Study (PSCS), by definition within PRC-027, must demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults. Most entities have internal procedures regarding the performance of coordination studies that produce the results required, but may not involve the exact same process or procedures that another entity follows to achieve Protection System coordination. The drafting team chose not to specifically dictate the elements of this process, but rather to continue to allow entities to “demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults” according to their own internal procedures.
The examples of information required in a “summary” of the results of a PSCS represent a minimum set of data that must be provided so the receiving entity can effectively assess coordination of the system. The drafting team has revised the examples to add clarity and the particular example provided in your comment has been removed.</td></tr>
<tr><td>Ameren</td><td>Yes</td><td>Note- No. 1 objection is above in Question 1
(2) Requirement R2 requires short circuit study every 24 months even though the drafting team’s own rationale is that other requirements will trigger Protection System Studies first. Thus we believe that R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of</td></tr>
</table>

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<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>commensurate importance.
(3) VSL escalation in 10 days is not representative of the severity of the violation. The drafting team correctly points out in R1 rationale that it “has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements.” We have about 500 Interconnected Elements per our present understanding of Draft 2 definitions and guidance. We recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity’s Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively. Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
2. The drafting team revised Requirement R2 to require, at least once every 60 months, Transmission Owners perform a short circuit study and calculation of fault current deviation for its Interconnected Elements or provide a technical justification why periodic fault current studies are not necessary for the coordination of Protection Systems associated with Interconnected Elements.
3. VSL issue</td></tr>
<tr><td>Manitoba Hydro</td><td>Yes</td><td>Although Manitoba Hydro agrees with question 3, we have the following general comments:
(1) R2, 2.1.1 - Reference to the Protection System Study should be the most recent Protection System Study to be consistent with the rest of the requirement and the use of the word ‘available’ is a little problematic. What if no study exists? As we read it, the requirement to do a study is within 48 months of the effective date of the standard, while the requirement to do a short circuit study is at least every 24 months. If the Protection System Study is not available, is there no requirement to do the short circuit study?
(2) R2, 2.2 - For clarity, we suggest rewording the first sentence to read ‘Within</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		30 calendar days after identification, through the calculation performed pursuant to Requirement R2, Part 2.1.2, of a deviation in...' (3) R3, 3.1 - No time frame is given and it is unclear as to whether these details are to be only for proposed or future changes or additions, or whether it can be 'notice after the fact' (when read with the remaining requirements, it would be assumed it is 'prior notice', but that's not clear on the face of this part 3.1). In addition, should 'facilities' be capitalized in 3.1? Also, there needs to be consistent references to 'changes and additions' or just 'changes' within this R3 as currently there are references to both made. (4) R3, 3.2 - We suggest moving the time frame to the start of the Part for consistency with the drafting of other Parts and for ease of reading. (5) R3, 3.3 - We believe that the timeline is incomplete. Assuming that the timeline is meant to be 'within 30 calendar days of the (proposed?) changes or additions being made'. (6) VSLs/VRF table: R1, R3 - For consistency, the references should read 'less than or equal to 10 calendar days' instead of '10 calendar days or less'. (7) VSLs/VRF table: R4 - All of the references to 4.1 appear to be incorrect because 4.1, as currently drafted, does not require confirmation of acceptance of the summary results.

Response: Thank you for your comment.

1. If you do not have a Protection System Coordination Study, you cannot perform a fault current comparison.

2. The drafting team considered this alternate language; however, we believe the existing language is sufficient.

3. 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 drafting team capitalized "Facilities" but believes the other language is appropriate as written.

4. The drafting team believes the overall language of the requirement is appropriate as written.

5. The changes noted in Requirement R3, Part 3.3 are not proposed changes, they are indentified as 'changes made to Protection

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td colspan="3">Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components'.
6. VSL language issue
7. VSL language issue</td></tr>
<tr><td>Operational Compliance</td><td>Yes</td><td>It would be great if NERC provided a common format for all of us to use when providing this information</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS.
The examples of information required in a "summary" of the results of a PSCS represent a minimum set of data that must be provided so the receiving entity can effectively assess coordination of the system. The drafting team has revised the examples to add clarity.</td></tr>
<tr><td>JEA</td><td>Yes</td><td>There is no place to put in a comment for R2 so this is for R2. We believe that the requirement to perform an analysis should be changed from once every 24 months to once every 36 months. Whenever changes are done to the system an analysis is done so this for areas that have not changed and we believe that once every 3 years should be sufficient.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on stakeholder comments, the drafting team extended the 24 month review of fault currents to 60 months.</td></tr>
<tr><td>Imperial Irrigation District (IID)</td><td>Yes</td><td></td></tr>
<tr><td>GP Strategies</td><td>Yes</td><td></td></tr>
<tr><td>Dominion</td><td>Yes</td><td></td></tr>
</table>

Organization	Yes or No	Question 3 Comment
SERC Protection and Controls Subcommittee (PCS	Yes	
seattle city light	Yes	
Certain Members of the ISO RTO Council	Yes	
Duke Energy	Yes	
US Bureau of Reclamation	Yes	
pacificorp	Yes	
Texas Reliablity Entity	Yes	
Tacoma Power	Yes	
City of Austin dba Austin Energy	Yes	
Independent Electricity System Operator	Yes	
Idaho Power Co.	Yes	
Exelon Corporation and its affiliates	Yes	
Xcel Energy	Yes	
City of Tallahassee	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the

Organization	Yes or No	Question 3 Comment
		Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.

Response: Thank you for your support.

Al M to review and provide answer

4. **In Requirement R4, the drafting team replaced the need to 'reach agreement' with 'confirming acceptance.' Do you agree with this change? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Quick summary:

16 no with comments

16 yes with comments

33 yes with no comments

1 no vote with comment VSL issue

Organization	Yes or No	Question 4 Comment
Manitoba Hydro	No	(1) R4, 4.2 - The concept of 'accept' the changes are problematic. We are unclear as to what exactly this means? Is it something more than acknowledging that the changes are occurring? Does it go so far as 'agreement' with the changes? What happens if the owner does not 'accept' the changes? (2) R4, 4.1 - For consistency with wording the in R3, 'planned change' should be 'proposed change' or 'addition'.

Response: Thank you for your comment.

1. Based on stakeholder comments, the drafting team modified Requirement 4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.

2. The suggested change has been made.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td>Georgia Transmission Corporation</td><td>No</td><td>1) The protection criteria and philosophies between entities can differ. For example, one entity may use the practice of coordinating for normal and single worst case contingency conditions, which is included in information/documentation provided to the neighboring entity in such Protection System Studies. The neighboring entity may have a slightly different protection criteria or philosophy, so exceptions may be required on a case by case basis using the “art and science” of protective relaying. Therefore, interpretation of ‘confirming acceptance’ means there may be differences in protection elements used by each entity but that there were no major disagreements and that generally the methods were acceptable and included using industry protection practices.
2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team acknowledges that entities may have differing protection philosophies. The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.
2. The drafting team believes that any conflict resolution should be handled through normal business practices.</td></tr>
<tr><td>Bonneville Power Administration</td><td>No</td><td>According to this standard, something as simple as changing a CT ratio must now be communicated to all interconnected functional entities and documented. The interconnected functional entities must then “confirm acceptance” of the CT ratio change before the change can be made. The acceptance must then also be</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		documented. This level of bureaucracy is unnecessary and counterproductive. The change from "reach agreement" to "confirming acceptance" is irrelevant.
Response: Thank you for your comment. **Yes, current transformer ratios are listed as one of the changes listed in Requirement R3, Part 3.1 that must be communicated. The drafting team does not understand any circumstance where a current transformer ratio in a Protection System would be changed that would not result in a change to the Protection System settings.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.**		
FirstEnergy	No	FirstEnergy proposes that R4 Part 4.2 be deleted. The requirement is overly burdensome and R4 part 4.1 should provide sufficient evidence of whether or not the entity receiving study results believed any further action was required. Absent any such notification, the party would by default be accepting of the information. In regard to need for "acceptance" prior to planned changes FirstEnergy does not believe this is necessary. The drafting team in its rationale provided for Requirement R1 indicated "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements" therefore we do not believe R4 part 4.2 is a necessary reliability requirement. Furthermore, other changes (R3 part 3.3) potentially trigger upgraded Protection System Studies being communicated without "acceptance" prior to their implementation.
Response: Thank you for your comment. **The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.**		

Organization	Yes or No	Question 4 Comment
Nebraska Public Power District	No	Getting acceptance within the required time frame is not in the control of the requestor. The concern is the numerous timelines in this standard that require timely responses will create an overly complex standard that will be difficult implement and to audit. The starting points for the timelines will be difficult to audit as well since much of this must be determined between two or more entities. How will enforcement view a requesting utility that sends a timely request but the response is a late confirmation of acceptance? The numerous time lines will create significant confusion and very complex data retention practices that will be difficult to track and difficult to audit. It appears the focus is more on time lines and the likely result is the content of the shared information will likely suffer due to the burden of tracking dated communications between entities. This draft standard includes time lines ranging from “prior to in service date, 30 days, 90 days, 6 months, 2 years and 4 years”. There should be fewer and simpler time lines with the focus on if the sharing of information took place and not on when did it take place. The SDT statement below should be generalized to the standard as a whole:”The SDT 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 SDT 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,”At a minimum remove the calendar day references and make them all 6 months for simplicity so the option is to use and agreed upon time or 6 months. Possible Suggestions: A simpler method would be after the initial 4 years to perform a study then every 24 months perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the interconnecting bus per Requirement R1 and demonstrate that the fault

Organization	Yes or No	Question 4 Comment
		model was provided to the interconnecting entities within this time period along with the settings so the receiving entity can review against their design. Auditing would verify this data was sent on a two year schedule. For new protection interfaces verify protection studies or relay settings or summaries of studies were exchanged for review prior to the equipment going in service.
Response: Thank you for your comment. **The drafting team believes the timeframes in the standard, as revised, are necessary and appropriate.**		
Ingleside Cogeneration LP	No	Ingleside Cogeneration still holds to the position that a dispute resolution process needs to be defined should we reach an impasse with the TO. R4 still requires that both parties “accept” the proposed change - which means that one or the other could unreasonably demand an Protection System-related expenditure without any need to demonstrate that a corresponding reliability benefit will be realized. It is not apparent to us that this situation is already addressed in NERC’s Rules of Procedure, which ultimately is the governing document for continent-wide Reliability Standards.
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal business practices.**		
National Grid and Niagara Mohawk (A National Grid Company)	No	It is not clear where the old text "reach agreement" and the new text "confirming acceptance" were/are used. Also, "confirming acceptance" is vague in meaning.
Response: Thank you for your comment. **The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td>Midwest Reliability Organization NERC Standards Review Forum</td><td>No</td><td>R4, Part 4.2: In consideration that R4, Part 4.1 already requires entities to review the results of a Protection System Study and provide any related feedback, recommend Part 4.2 be removed from the standard. Without additional guidance within the standard specifying the timeframe in which an entity must provide its confirmation, the entity implementing the planned change could potentially be left waiting indefinitely for confirmation despite the study already being reviewed and accepted as part of Part 4.1. If part 4.2 is not removed, recommend that additional guidance be provided concerning time frames (90 days?).</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.
Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.</td></tr>
<tr><td>Xcel Energy</td><td>No</td><td>Requirement 4.2 requires entities to receive evidence confirming acceptance of changes prior to implementing these changes. This coordination already occurs, and we believe this should be a standard practice for all applicable entities. However, we do not agree that this documentation-only requirement is necessary or beneficial to reliability. Instead, we believe this would deter valuable resources to unnecessary compliance evidence activities. Therefore, we recommend that this requirement be eliminated.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.
Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
completed a review of the Protection System(s) changes and any identified coordination issues were resolved.		
Wisconsin Electric Power Company	No	The current draft standard lacks any clear responsibility for performing the complete Protection System Study, especially if the interconnected parties cannot accept or reach an agreement. The recommended change is to make the Transmission Owner accountable for the overall Protection System Study, at least at the Generator-Transmission interconnections. The other entities such as Generator Owners should be responsible to provide the necessary data required for the overall study. This makes the most sense based on limited resources and capabilities, as well as access to all data. This is especially true for independent Generator Owners that operate in the deregulated market. It is not feasible to make all entities somehow responsible for the study.
Response: Thank you for your comment. **The drafting team believes that the Generator Owner is an appropriate Applicable Entity for this standard since they often apply Protection Systems that require coordination with other owners' Protection Systems.**		
Southern Company	No	The parties at the opposite ends of an interconnecting facility may not have the same protection philosophies, and acceptance may not be achievable. It is unclear what it means to confirm acceptance. Does this mean that the two must come to an agreement for each other's protection system settings, or is it acceptable to agree that we disagree?
Response: Thank you for your comment. **The drafting team acknowledges that entities may have differing protection philosophies.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.**		
City of Tallahassee	No	These phrases do not appear to be contained within draft two.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team intent was to indicate the thought behind the fact that language was changed in R4.2 to indicate ‘confirm the owner(s) of each Facility associated with the affected Interconnected Element accept.’
Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>No</td><td>This change is more ambiguous than reach agreement. How can changes to Protection Systems occur unless agreement is reached via a signed off Protection System Study? What does it mean to confirm acceptance?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The confirming acceptance indicates that the entity has not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agree with the other entities philosophy.
Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.</td></tr>
<tr><td>Hydro One Networks Inc.</td><td>No</td><td>This change seems more ambigious than “reach agreement”. How can changes to Protection Systems occur unless agreement is reached via a signed off Protection System Study? What does it mean to “confirm acceptance”?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The confirming acceptance indicates that the entity has not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agree with the other entities philosophy.
Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
Texas Reliablity Entity	No	TRE agrees with the need to notify the Facility Owner of the proposed changes. However, if the receiving entity does not agree with the proposed changes, there needs to be a venue to reach consensus. The receiving entity should be able to suggest changes based on technical rationale to resolve the disparities. A provision for dispute resolution needs to be provided. TRE suggests re-wording R4.2 to - "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, notify the Facility owner(s) associated with the affected Interconnected Element. If consensus cannot be reached on the proposed Protection System(s) changes, each entity shall document the technical rationale for its position on each disputed issue prior to implementation."
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal business practices.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.**		
Pepco Holdings Inc & Affiliates	No	We find that changing the wording from "confirming acceptance" to "reaching agreement" does little to address the root problem associated with mandating mutual agreement. We suggest 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 I f 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

Organization	Yes or No	Question 4 Comment
		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 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

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>“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.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that any conflict resolution should be handled through normal business practices.
The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.
Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element has completed a review of the Protection System(s) changes and any identified coordination issues were resolved.</td></tr>
<tr><td>ACES Standards Collaborators</td><td>Yes</td><td>(1) We had no issues with the use of agreement in the previous version. Coordination of protection systems is important enough to obtain agreement. Furthermore, we believe confirming acceptance and reaching agreement are synonymous. If two entities need to “resolve differences and confirm acceptance that their Protection Systems are coordinated,” that is the same as stating that the entities need to reach an agreement.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment and support.
The changes were made based on previous comments from those that believed agreement was too strong. They indicated that confirming acceptance indicates that the entity has not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agree with the other entity’s philosophy.
Note: The drafting team revised Requirement R4, Part 4.2 to read: 4.2. Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, receive confirmation that the other owner(s) of each Facility associated with the affected Interconnected Element have completed a review of the Protection System(s) changes and any identified coordination issues were</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
resolved.		
SERC Protection and Controls Subcommittee (PCS	Yes	1) The protection criteria and philosophies between entities can differ. For example, one entity may use the practice of coordinating for normal and single worst case contingency conditions, which is included in information/documentation provided to the neighboring entity in such Protection System Studies. The neighboring entity may have a slightly different protection criteria or philosophy, so exceptions may be required on a case by case basis using the "art and science" of protective relaying. Therefore, interpretation of 'confirming acceptance' means there may be differences in protection elements used by each entity but that there were no major disagreements and that generally the methods were acceptable and included using industry protection practices. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance.
Response: Thank you for your comment and support. **1. The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, receive confirmation that the other owner(s) of each Facility associated with the affected Interconnected Element have completed a review of the Protection System(s) changes and any identified coordination issues were resolved.** **2. The drafting team believes that any conflict resolution should be handled through normal business practices.**		
Dominion	Yes	1) Dominion interprets the wording "confirming acceptance" to mean that there are no major disagreements and that generally the methods between entities are acceptable using industry protection practices even if different protection

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>setting philosophies’ exists.
2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance. The initiating party should not be restricted from applying appropriate settings due to the lack of acceptance confirmation from the other entity.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment and support.
1. The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, receive confirmation that the other owner(s) of each Facility associated with the affected Interconnected Element have completed a review of the Protection System(s) changes and any identified coordination issues were resolved.
2. The drafting team believes that any conflict resolution should be handled through normal business practices.</td></tr>
<tr><td>ReliabilityFirst</td><td>Yes</td><td>ReliabilityFirst abstains and offers the following comments for consideration:
2. Requirement R4 Violation Severity Level
a. During the previous comment period, ReliabilityFirst recommended that VRF for R4 be changed to “High” since this is dealing with interconnection protection systems. The SDT response by indicating they “...believes the VRF for Requirement R4 more aligns with the NERC criteria for a medium risk. “ After reading the NERC criteria for a medium risk, ReliabilityFirst would agree only if the Time Horizon of this requirement is changed to “Long Term Planning”</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that the Time Horizon for Requirement R4 is assigned correctly at “Operations Planning” and also</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
believes the VRF of “Medium” is correct. No changes were made.		
PPL Corporation NERC Registered Affiliates	Yes	There is no clear responsibility in the standard if both parties cannot confirm acceptance.
Response: Thank you for your comment and support. **The drafting team believes that any conflict resolution should be handled through normal business practices.**		
Independent Electricity System Operator	Yes	We agree with the intent of the proposed changes, but believe some editorial changes are necessary for more clarity. We suggest the following wording for the SDT’s consideration: 1. “Confirm with the owner(s) of each Facility associated with the affected Interconnected Element that it accepts (or acceptance of) the resulting Protection System(s) changes.” 2. In fact, Part 4.1 could also be worded to add clarity:”Within 90 calendar days after receipt of the proposed Protection System(s) changes,”
Response: Thank you for your comment and support. **1. Based on stakeholder comments, the drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, receive confirmation that the other owner(s) of each Facility associated with the affected Interconnected Element have completed a review of the Protection System(s) changes and any identified coordination issues were resolved.** **2. The “receipt” in Requirement R4, Part 4.1 is referencing the summary results of the Protection System Coordination Study. The drafting team believes this is clear and unambiguous and declines to make the suggested change.**		
Western Small Entity Comment Group	Yes	
Imperial Irrigation District (IID)	Yes	

Organization	Yes or No	Question 4 Comment
Southwest Power Pool Reliability Standards Development Team	Yes	
GP Strategies	Yes	
Luminant	Yes	
seattle city light	Yes	
Florida Municipal Power Agency	Yes	
Certain Members of the ISO RTO Council	Yes	
Duke Energy	Yes	
JEA	Yes	
US Bureau of Reclamation	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	
pacificorp	Yes	
Western Electricity Coordinating Council	Yes	
Dynegy	Yes	
American Transmssion Company, LLC	Yes	

Organization	Yes or No	Question 4 Comment
Essential Power, LLC	Yes	
American Electric Power	Yes	
Liberty Electric Power LLC	Yes	
Public Service Enterprise Group	Yes	
Ameren	Yes	
Tacoma Power	Yes	
Entergy Services, Inc. (Transmission)	Yes	
City of Austin dba Austin Energy	Yes	
ITC	Yes	
Idaho Power Co.	Yes	
Sacramento Municipal Utility District	Yes	
Exelon Corporation and its affiliates	Yes	
Cogentrix Energy Power Management, LLC	Yes	
Kansas City Power & Light	Yes	
NV Energy	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the

Organization	Yes or No	Question 4 Comment
		Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.

Response: Thank you for your comment.

The drafting team revised the VSLs for Requirement R2.

5. **The requirements and associated measures were modified to indicate that information was 'provided' instead of 'demonstrating that each affected entity received notification.' Do you agree with this change? If not, please provide specific suggestions for change in the comment area.**

Quick summary:

11 no with comments some of these were general

19 yes with comments many of these are general

23 yes with no comments

5 no vote with comment VSL issue again and mostly general comments

Organization	Yes or No	Question 5 Comment
ACES Standards Collaborators	No	(1) The measures do not match the requirements. For example, R4 requires entities to confirm acceptance, which would demonstrate that each affected entity received notification. Again, the drafting team is using synonyms that produce the same result as the prior draft. To show evidence that the information was "provided" would have to be some sort of notification of receipt. (2) Does the drafting team intend further actions for coordination beyond providing the studies to applicable entities? (3) We recommend the drafting team develop an RSAW to better explain how compliance would be measured against this standard. Thank you for the opportunity to comment.

Response: Thank you for your comment.

1. The drafting team intends that information is "provided" (synonymous with "sent") and receipt of delivery is not required.

2. Yes, the drafting team intends for the receiving entity to review the Protection System(s) changes and identify any coordination

Organization	Yes or No	Question 5 Comment
issues. **3. The drafting team agrees with this approach and will work with NERC Compliance staff to develop an RSAW.**		
Independent Electricity System Operator	No	(1) We do not have a strong view one way or the other with respect to “provided” versus “demonstrating”. However, the wording used among Measures needs to be consistent. For example, in M1 the wording is “Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, and 1.1.3 is a dated Protection System Study, or the summary results of...” seems reasonable since it shows the examples for “acceptable evidence”. The examples listed illustrate what constitute “acceptable evidence”. However, in M2, the wording “Acceptable evidence for Requirement R1, Part 1.2 demonstrating that the summary results of each Protection System Study (hard copy or electronic file formats) was provided....” Does not illustrate what constitutes “acceptable evidence”, thereby leaving that to interpretation. We suggest M2 (and M4) be reworded along the same line as that for the other Measures (M1, M3, M5 to M9). (2) The Comment Form does not have a question on “Do you have any other comments?” Therefore, we are submitting the following comment under this Question. We reiterate our concerns previously expressed with respect to PRC-001: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. If this is a training requirement, it should be transferred to the appropriate PER standards. c. Measures M1 is removed from the standard. This does not conform with the Elements of a Reliability Standard template, specifically those specified in the

Organization	Yes or No	Question 5 Comment
		“Mandatory and Enforceable Sections of a Standard”. d. 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. However, leaving this not measurable and unnecessary requirement in PRC-001-3 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 could have proposed 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. The SDT’s response to our previous comment was “This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff.” We do not believe that the 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.

1. The drafting team modified the Measures to address your comment.

Organization	Yes or No	Question 5 Comment
2. The drafting team has recommended that:PRC-001 Requirement R1 issue		
seattle city light	No	Because there is no "other comments" section included in this comment form, the following comments about the timelines for specific actions are appended here. 1. (R3.2) "Data Requests . . . . 30 Days or agreed to schedule' Seattle requests that "agreed to schedule" be clarified, in particular the limits in determining this schedule. If no further clarity is added, Seattle suggests that "or agreed to schedule" simply be deleted. 2. (R2.1) Short Circuit Study . . . . . . 24 months SCL recommends that the time line of 24 months be removed and that the 10% change in fault current criteria serve as the replacement for this requirement. 3. (R4.1) "Review PS Study . . . . .90 Days or agreed upon schedule" Seattle is concerned that, depending upon the complexity of the study, a lot of back and forth communication between the utility entities may be required. Please clarify 4. 1) if each response to, or revision of the study trigger another 90 day review period and 5. 2) the limits as the defining an "agreed to schedule." If no further clarity is added regarding agreed to schedules, Seattle suggests that "or agreed to schedule" simply be deleted.
Response: Thank you for your comment. **1. The drafting team intends that an agreed upon schedule is the schedule all involved parties agree to. In most cases, the drafting team believes the mutually agreed upon schedule would be a longer time frame than the maximum days specified in the requirement.** **2. Since the 10% threshold cannot be determined unless the study has been done, the drafting team believes it is appropriate for**		

Organization	Yes or No	Question 5 Comment
there to be a requirement to do the study. Note: the time frame has been changed to 5 years. **3. The 90 days or the agreed upon schedule only pertains to the initial review and response of the Protection System Coordination Study. The drafting team realizes that there could be a lot of back and forth after the initial review and response but there is no associated time frame.** **4. Technically your statement could be correct; however, the drafting team believes both parties will have an incentive to complete the process as soon as practical.** **5. The drafting team intends that an agreed upon schedule is the schedule all involved parties agree to. In most cases, the drafting team believes the mutually agreed upon schedule would be a longer time frame than the maximum days specified in the requirement.**		
Bonneville Power Administration	No	1. BPA believes that the requirements and measures are onerous and should be eliminated. The change in wording is irrelevant. Additional Comments 2. R1.1 requires a protection system study to be performed, but does not explain what is required for a protection system study.R1.2 lists some minimum requirements of a protection system study, but leaves many unanswered questions, for example: Which relays must be included in the study? Where are the faults to be applied? What contingencies should be applied for the study? How many buses back into the system must be reviewed? 3. R1.1.2 introduces the term “interconnecting bus” with no definition of what it is. 4. R2 is a requirement that pertains to each facility associated with an interconnected element. The use of the word “associated” is too vague and leaves the interpretation of this requirement wide open.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>5. In R2, the need to perform a new protection system study is based on a 10% or greater increase in fault current. Since many relays are based on impedance or differential methods, the value of fault current has no bearing on their need for a coordination review. R2, therefore, results in an unnecessary and useless burden when applied to elements protected with these relays.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
1. The drafting team believes the requirements and measures support the reliability intent of the standard.
2. The drafting team believes the relays to be considered are identified in the Facilities Section of the standard which reads: “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.” The conditions under which the PSCS is performed are dependent on the owner’s philosophies and practices. The drafting team recognizes that philosophies and practices vary depending on the owner and that is why it is important to share the results with the other owners.
3. Based on your comment, the drafting team has designated the interconnecting bus in the example figures to provide clarity.
4. The drafting team believes the word “associated” in the context used is clear.
5. The drafting team revised Requirement R2 to allow a technical justification explaining why Fault current does not affect the Protection System coordination.</td></tr>
<tr><td>Florida Municipal Power Agency</td><td>No</td><td>First, there should be an “any other comments” question. Seeing that there isn’t one, we are adding our other comments here.
1. R3 - There should be thresholds of change to the bullets.
For instance, changing the no-load tap changer of a GSU does minimally change the impedance of the GSU).
transmission line neighbor installing a long chain link fence along the ROW will have a minimal impact on mutual coupling. These minimal changes do not require redoing the study, so, what percentage change in impedance requires redoing the study?</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that information about any change (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 Element.</td></tr>
<tr><td>Imperial Irrigation District (IID)</td><td>No</td><td>IID believes the affected entity need to demonstrate it received notification.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team intends that information is “provided” (synonymous with “sent”) and receipt of delivery is not required.</td></tr>
<tr><td>Nebraska Public Power District</td><td>No</td><td>Measurement 9 for R4 requires confirmation of acceptance prior to implementation of any planned protection system changes. This appears to be similar to ‘demonstrating that each affected entity received notification.’ The concern is holding one company responsible for actions of another that is not under the requestor’s control. It is recommended that there be clarification that if the requestor does not get confirmation of acceptance in the proper time line then the requestor is not accountable or subject to violations. Another option is to remove R4.2.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes that any conflict resolution should be handled through normal business practices. The drafting team believes the requestor cannot be held accountable when the other party does not respond.</td></tr>
<tr><td>CenterPoint Energy</td><td>No</td><td>Providing schedule information and project details by a transmission service provider to a generation entity may be governed by established, regional market rules that provide for what information can be shared with competitive entities. There are many installations in the ERCOT System where the owner of the interconnecting switchyard is not the same entity as the owner of the interconnected generation facility.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **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 proper coordination of the Protection Systems covered by this proposed standard.**		
Salt River Project	No	Receipt of confirmation should be required to confirm coordination.
Response: Thank you for your comment. **The drafting team intends that information is “provided” (synonymous with “sent”) and receipt of delivery is not required.**		
NextEra Energy	No	See page 19 of the redline PRC-027 Guidelines and Technical Basis. “ System condition used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions.”Please clarify that “single contingency conditions” refers to breaker failure or protective system failure. It is not intended to mean single contingency operating conditions such as line or transformers out of service.
Response: Thank you for your comment. **The use of ‘single contingency conditions’ in this context is to indicate facility outages. e.g. line out.**		
Xcel Energy	No	Since the SDT did not provide a question for “any other comments”, Xcel is using this question for that purpose. 1) We would appreciate some additional clarity as to what transmission fault conditions need to be evaluated by the Generator Owner. Figure 2 does not apply to very many of our units (on most, Breaker A would not exist and Breaker C is part of a breaker-and-a-half scheme). Is the generator supposed to evaluate only faults on the line between the GSU Transformer and the substation or evaluate his protection settings for a fault on any of the transmission lines leaving the substation?

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>2) Can the drafting team, either as part of the Application Guideline or in a separate document provide a list of protective functions the Generator Owner needs to evaluate or is it the complete suite of protective functions defined in the NERC SPCS Generator - Transmission Protection Coordination Guideline?
3) Requirement 3.1 is onerous as it requires notification for an open ended “when the proposed change modifies the conditions used in the coordination of Protection Systems.” The requirement should be limited and instead provide a simple list of element changes that generally affect coordination with adjacent Elements.
4) Similarly for 3.3, we recommend that this be modified to limit the scope to only changes that result in a change of performance or ratings. For example, settings that change the alarm conditions for a device or a “like-for-like” replacement should not be required to be communicated. Communicating every change would not improve reliability and would instead deter valuable resources to unnecessary compliance evidence activities.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. In the situation cited, the Transmission Owner would plot the Faults to ensure there are no coordination issues with the settings provided by the Generator Owner. Conversely, the Generator Owner would be responsible to ensure the settings provided by the Transmission Owner for breaker B does not result in coordination issues with generation Protection Systems. Example: that a Transmission Owner back-up relay does not operate before a Protection System designed to isolate a station service bus.
2. The drafting team has decided not to reference the subject document; however, the drafting team recognizes that it would be a good reference.
3. The drafting team believes that the bulleted items in Requirement 3, Part 3.1 provide the ‘list’ suggested.
4. The drafting team believes that although these circumstances will be rare, the noted information should be shared with the other entity so that they can update their records and provide any needed feedback.</td></tr>
<tr><td>City of Austin dba Austin Energy</td><td>Yes</td><td>(1) Austin Energy (AE) notes an inconsistency in R1.1.3 and the flowchart on page 22 of the clean version of Draft #2. R1.1.3 states that a Protection System</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		Study is required "according to an agreed upon time frame" whereas the flowchart on page 22 says "perform the PSS within 6 months." AE asks the SDT to update the flowchart to match the requirement language. (2) AE believes the VSLs for R4 are not consistent with the language of the standard, specifically R4.1 and R4.2. For example, the Severe VSL language should read "The responsible entity reviewed the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and responded as to whether further action is required, all per R4, Part 4.1, but was late by more than 30 calendar days. OR The responsible entity failed to review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required, all per R4, Part 4.1. OR The responsible entity failed to confirm acceptance of any resulting Protection System(s) changes prior to implementing any planned change(s) associated with Requirement R3, Part 3.1 per R4, Part 4.2." AE is concerned about the current VSL language because it indicates the need to confirm acceptance of planned changes (e.g., new installation) instead of the resulting Protection System(s) changes.
Response: Thank you for your comment. **1. Based on your comment, the flowchart has been revised.** **2. The VSLs have been revised to match the revised requirements.**		
Dominion	Yes	1). Please replace "detect Faults on the BES Transmission System" with "protect the BES Transmission System" in all three places it appears in Figure 3. This proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 2). Dominion respectfully disagrees with the SDT feedback comment on Draft 1 where it was recommended to remove references from one Requirement to

Organization	Yes or No	Question 5 Comment
		another Requirement. Dominion was not challenging consistency with the recommendation but were stating the need to simplify the wording in the standard. Each Requirement can stand on its own without the additional Requirement reference. By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement due to the fact that that it causes you to read between Requirements. Isn't this the purpose of the Process chart in the guidelines? 3). Under R1 - MI measure wording does not read as a completed statement. Dominion suggests removing 'that' from the first sentence to "....demonstrating time frames". 4). Dominion respectfully disagrees with the SDT feedback that in R2 the term "deviation" is synonymous with "change". Deviation refers to variation from a standard, norm or mean. This is not a statistical calculation but a simple measure of change 5). In R3- 3.2, there appears to be a formatting issue. Any Requirement that references a calendar day is worded where the Calendar date is at the beginning of the statement; for example R3- 3.3. Need to change wording in R3- 3.2 for consistency throughout document to read "Within 30 calendar days of receiving a request or according to an agreed upon schedule, requested information related to coordination...."). 6) In Draft #1 Dominion wrote: "Throughout this Draft 1 of the standard, there are references that illustrate documentation requirements that are inconsistent. Recommend all be written as "(hard copy or electronic file formats)". The SDT responded saying "Each measurement in the standard (M1 through M10) has as evidence the statement "dated documentation (hardcopy or electronic file formats)." This is not the case; the point was that M1 reads "either in hardcopy or electronic file formats". This is minor but needs to be changed for

Organization	Yes or No	Question 5 Comment
		consistency.
Response: Thank you for your comment. **1. The drafting team used the term ‘detect Faults on the BES Transmission System’ to indicate those Protection Systems that may require review with other owners Protection Systems. The drafting team revised the phrase to read “installed for the purpose of detecting Faults on BES Elements” for consistency with the Facilities section of the Applicability. It is also noted that the identified interpretation was for the term ‘transmission Protection Systems’ which is not used in this Standard. Figure 3 has been modified to provide consistent language.** **2. The drafting team still believes the references to other requirements in the standard are the best way to both maintain consistency and to describe the requirements. This approach has been approved through the Quality Review process and is used in other NERC Reliability Standards.** **3. Measure M1 was revised based on your comment.** **4. The drafting team made the suggested change.** **5. The drafting team believes Requirement R3, Part 3.2 is appropriate as written.** **6. The drafting team made the suggested change.**		
Western Small Entity Comment Group	Yes	The comment group has no comments regarding this question. This form provides no general comment area, so we are providing our additional comments here. We referenced the WECC Position Paper in the last round of comments, but now see that WECC did not submit comments. We urge the SDT to take a look at the paper. We received our copy from steve@wecc.biz . We can also forward a copy if an email address is provided. For the team’s convenience, here is the relevant text: “WECC staff and WECC subject matter experts have reviewed the proposed standard and agree with the purpose of the standard. WECC staff and WECC subject matter experts agree that Protection Systems must be coordinated. However some subject matter experts believe that the proposed standard requires more documentation than is necessary and that the requirement to provide a hard copy or an electronic copy of each Protection

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>System Study is administratively burdensome and not reflective of the intent of Results Based Standards. These subject matter experts believe that evidence that studies are coordinated and that entities have agreed to the results of System Protections Studies is adequate.” We see that the SDT responded to Salt River Project’s and other’s similar concerns regarding hard copies by stating that that only summaries are needed, but we still see the standard as overly burdensome compared with the possible benefit. Tennessee Valley Authority, Dominion Power, Southwest Power Pool, the Nebraska Public Power District, Dairyland Power Cooperative, the Bonneville Power Administration, and the SERC Protection and Control Subcommittee provided some specific suggestions to reduce documentation burden which were all rejected. We urge the SDT to review these recommendations again.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team believes the requirements in the standard accomplish the reliability objective of this standard and are not overly burdensome.</td></tr>
<tr><td>Duke Energy</td><td>Yes</td><td>Additional comment:
R2.1.1 refers to “maximum available Fault current values”, but it’s unclear from the requirement or the Guidelines and Technical Basis how “maximum” is defined. We believe it should be maximum generation and all Facilities in service.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team had included in the Guidelines and Technical basis section the following which it believes answers this question: ‘Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency condition’.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
Tacoma Power	Yes	Additional Comments: 1. Why is there a version 4 for PRC-001 (under Version History) when the standard being balloted is version 3 (PRC-001-3). 2. PRC-027-1 does not appear to impose any requirements as to how quickly issues identified in a Protection System Study are addressed. It may be difficult to impose such a timeframe since some issues may just require a relay setting change, while others may require more drastic scheme modification, including design, procurement, installation, and commissioning. Perhaps requirements could be added to develop, within a specified timeframe, and then implement a mutually agreeable Corrective Action Plan. As written, it appears that an entity can be compliant with Protection System Studies that always indicate existing coordination issues, which does not completely achieve the purpose of the standard. Without a mechanism to close the loop, PRC-027-1 appears to require a lot of documentation and coordination without any guarantee that existing coordination issues will ultimately be resolved. R4.1 really only requires entities to come to terms on the Protection System Study, but does not explicitly require any other course of action on existing coordination issues. 3. In M1, the sentence ending in "...demonstrating that the time frames specified in Parts 1.1.1 and 1.1.2" in a fragmented sentence. Also, should this sentence have "and 1.1.3" at the end? 4. M2 is a fragmented sentence. 5. M4 is a fragmented sentence. 6. As written, it may be difficult to audit parts of R3.1. Some of the language seems to be subjective and implicitly left to engineering judgment. First, it is not completely clear what the drafting team intended by the wording "associated with" or how an auditor might interpret that wording. Second, please consider changing "...or at other facilities when the proposed

Organization	Yes or No	Question 5 Comment
		change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)" to "...or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s), as stipulated in the existing Protection System Study." This should make it easier to audit this aspect of R3.1. Third, regarding the second through fourth bullets, engineering judgment will be required to determine when impedances need to be changed. For example, minor modifications could be made to a transmission line that, in a purely academic sense, could change the impedance; however, an entity may opt not to update the impedance based upon engineering judgment that the change is not significant to the impedance model. 7. For emphasis, under R3.2, considering changing "...within 30 calendar days of receiving a request or according to an agreed-upon schedule" to "...within 30 calendar days of receiving a request or according to an agreed-upon schedule, which may be longer or shorter than 30 calendar days." 8. R4.2 does not seem to explicitly require that a Protection System Study be completed before implementing changes indicated in R3.1, only that the changes are accepted. 9. R1.1.3 seems to suggest that the Protection System Study must be completed prior to implementation. However, according to the flow chart, it appears that a Protection System Study could be produced (in theory) six months after the changes were made. Furthermore, the flow chart applies the six-month timeframe even to R1.1.3, which does not match the text in R1.1.3.

Response: Thank you for your comment.

1. With the approval of PRC-027, PRC-001-3 will need to be revised as noted in the posted PRC-001-4

2. R4.1 really only requires entities to co

Organization	Yes or No	Question 5 Comment
3. **4.** **5.** **6.** **7.** **7.** **8.** **9.**		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with question 5, we have the following general comments: (1) M1 - The word ‘that’ in the third line should be deleted and we believe that the words ‘is dated documentation’ are missing after ‘Acceptable evidence for Requirement R1, 1.2. (2) M3 - For consistency, the word ‘formula’ should be replaced with calculation in Requirement R2, 2.1.2. (3) M4 - For clarity and consistency with the other Measures, we suggest rewording the opening sentence to read ‘Acceptable evidence for Requirement R2, Part 2.2 is dated documentation (hard copy or electronic file formats) demonstrating that the updated Fault current values were provided within....'. (4) M5 - The wording of this section does not match the wording of the requirement. The words ‘in hard copy or electronic file formats’ should follow the word summary, not after the word settings.
Response: Thank you for your comment.		

Organization	Yes or No	Question 5 Comment
1. The noted changes have been made **2. The noted change has been made** **3. The noted change has been made** **4. The noted change has been made**		
Sacramento Municipal Utility District	Yes	Although this is unrelated to Question 5 there was no other space allocated for the for “any other comments.” While this is most likely a clerical error, we feel it is not appropriate to post a standard without making such a question available.
Response: Thank you for your comment. **The format used was approved by NERC.**		
American Electric Power	Yes	Because the comment form provides no section to provide “general comments”, AEP offers them below. AEP would like to inform the drafting team that our negative vote on this standard is primarily driven by A) the lack of clarify in regards to its scope (as discussed in the response to Q2) and B) the timeframe allotted to perform the Protection System Study (as discussed in the response to Q3). C) It would be more appropriate for R 1.1.1 to be included in the implementation plan, rather than embedded within the standard itself. D) The proposed standard is difficult to follow, in the way that it jumps back and forth among requirements. We would encourage any changes which might increase the readability of the proposed standard.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.
A) See Q2 - recommends replacing all references to “generator Protection Systems” with “Generator Owner equipment that provides backup system protection
B) 48 month timeframe
C) R1.1.1 in implementation plan?
D) The drafting team has considered several options.</td></tr>
<tr><td>ITC</td><td>Yes</td><td>1. Figures 1-5 designate a preferred responsibility of coordination on either entity which contradicts with intent of R3. R3 details all the changes which must be provided to the adjacent utility, seemingly so they can coordinate their protection over yours. However, Figures 1-5 place the coordination responsibility on the utility which does not own the Protection System. I agree that R3 should remain almost as-is. However, the coordination responsibilities in Figures 1-5 should be reversed or preferably removed. Owner R should be responsible for coordinating Breaker A relays. Only the owner should be responsible for coordinating this relay.
2. SDT needs to define the term “interconnecting bus” and perhaps identify the interconnecting bus in Figures 1-5.
3. In Figures 1-4 the Interconnected Element is a line.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. Figure 5 issue
2. Define interconnecting bus? Add to figures
3. As noted in 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.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
FirstEnergy	Yes	FirstEnergy supports the change described by Question 5. Other comments from FirstEnergy in addition to the specific questions asked by the drafting team: A) PRC-001-3 EFFECTIVE DATE: The PRC-001-3 standard needs to be edited to match what is stated in the Implementation Plan. The Implementation Plan indicates that both PRC-027-1 and PRC-001-3 will become effective at the same time which is stated as being the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. However, the PRC-001-3 standard in its Effective Date section indicates the first day of the first calendar quarter twelve months following applicable regulatory approval. B) PRC-001-3 VERSION HISTORY: The Version History of the PRC-001-3 standard needs some clean-up. The table reflects a "version 4" however this project creates version 3. Looks l+A74ike the fix is to delete the row labeled version 3 and change the version 4 to reflect 3. The description text in that row is correct. C) PRC-001 VERSION CHANGES: NERC needs to consider what it plans to do with the existing NERC BoT Approved versions PRC-001-1.1 and PRC-001-2 which have yet to be filed with FERC. It is recommended that NERC suspend the filing of those standards, keep it simple and file PRC-001-3 with this project. This will avoid undo industry confusion and transition. D) PRC-001-3 MISC CLEAN-UP: Section D, Part 1.1 revise Compliance enforcement authority" to read "Compliance Enforcement Authority (CEA)". This is a defined glossary term and is shown capitalized in other areas of the standard. In the second sentence, capitalize "entity" in the reference to "Regional entity". E) PRC-001-3 R1: Seems odd to have a standard with only one requirement. The requirement states "Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>protection system schemes applied in its area." FE proposes that R1 or an alternate be moved to PER-005.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
A. All are PRC-001 issues
B.
C.
D.
E.</td></tr>
<tr><td>National Grid and Niagara Mohawk (A National Grid Company)</td><td>Yes</td><td>National Grid offers the following additional comments that do not pertain to Question 5. The comments are included here since the Comment Form did not have an additional question concerning if we had additional comments.
1. Page 4: Other Aspects of coordination of Protection Systems addressed by other Project needs to be included in the final standard since it delineates what is not included in this one.
2. Page 8: Para.R2.1.2 should be reworded as it allows for a series of increments in fault current each less than 10% but which when summed over a number of review periods could collectively exceed 10%.
3. Application Guidelines:
a. Page 21: “Data used to determine Fault currents....” is essentially the short circuit model and the associated data base of line, transformer and generator impedances and connections. If that what is expected then it should be so stated otherwise “data” leaves a lot open to the reader’s conjecture.
b. Page 25: Decision point regarding R2.1.2 has the same issue as identified above in comment 2.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		c. Diagrams Fig. 1, 2, 3, 4, 5: The text that goes with these diagrams is inappropriate in its assignment of responsibilities for who reviews what coordination and the change of wording from “verify” to “review” does not resolve this problem. It is a protection system owner’s responsibility to coordinate their system with adjacent systems and it is the same owner’s responsibility to model adjacent systems in sufficient detail to enable that owner to perform that coordination. 4. Fig . 2, 5: The text refers to “generator protection” which can mean a wide range of protection functions such as but not limited to those related to voltage, frequency, loss of field, over-excitation and more. These were excluded on page 4 of the standard and their exclusion here should be emphasized. 5. Fig. 3, Notes following figure 3 exclude reverse power as being a protection system installed to detect faults on the BES Transmission System. We disagree. In our system and other systems in NE reverse power was historically installed specifically to detect and clear backfeed to a faulted transmission system.

Response: Thank you for your comment.

1.

2.

3a

3b

3c

4.

5.

Organization	Yes or No	Question 5 Comment
Certain Members of the ISO RTO Council	Yes	NERC must continue to correct such requirements, as it is not the responsibility of the entity subject to a requirement to ensure another party acts.
Response: Thank you for your comment.		
SERC Protection and Controls Subcommittee (PCS	Yes	Other comments (not associated with Question 5) are being provided which could not be addressed in the questions listed above: 1). R2 requires short circuit study every 24 months even though the SDT's own rationale is that other requirements will trigger Protection System Studies first. Thus R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. 2). Please replace "detect Faults on the BES Transmission System" with "protect the BES Transmission System" in all three places it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 3). VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it "has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements." Many entities have numerous Interconnected Elements, and recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity's Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively. Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation. 4). Throughout the 1st and 2nd draft of this standard, there are Requirements

Organization	Yes or No	Question 5 Comment
		that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.1.1, R2.1.2, R2-2.2, R4-4.1, R4-4.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. We appreciate the Drafting Teams perspective, but the SERC PCS believes that such cross references are confusing. 5). Under R1 - MI measure wording does not read as a completed statement. Suggest removing 'that' from the first sentence. 6) The process chart is a direct indication that this process and undertaking for entities will be overwhelming. New systems will be required to track many details of timeframe requirements and communication dates. Additional resources will be required placing increased workload for an effort to change the process that already works for us when working with other entities. The Drafting Team indicated, 'there is no evidence there is widespread miscoordination of protection systems.'

Response: Thank you for your comment.

1. The drafting team does not see the direct correlation between the studies required in this Standard and the noted studies in the TPLs. Additionally, The drafting team believes that a 60 month period for subsequent studies may not identify incremental increases in fault currents that may impact Protection System operations.

2. Figure 3 issue: detect Faults on the BES Transmission System" with "protect the BES Transmission System"

3. VSL issue

4. The format of this Standard has been approved through the NERC QR process as appropriate

5. The suggested change has made

6. statement but no suggested change

Organization	Yes or No	Question 5 Comment
Texas Reliablity Entity	Yes	OTHER COMMENTS (not responsive to any specific question asked above): R2.2: We suggest a minor change "...indicates a deviation in ***single line to ground or 3-phase*** Fault current of 10% or greater ....” R3.1: Based on recent work by the Protection System Misoperation Task Force (PSMTF), changes in logic settings should also be included (e.g. directionality V/Q logic, trip equations, carrier echo logic and coordination timers, carrier dip switch settings, etc.). We would suggest modifying the first bullet to say”...modification of: protective relays or protective function or logic settings, communication systems,....” The SDT may also want to consider adding an item to the list - “Changes to the transmission system topology that change the equivalent impedance or fault current.”
Response: Thank you for your comment.		
Georgia Transmission Corporation	Yes	Repeat of SERC PCS Other comments are being provided which could not be addressed in question 1 - 5 listed above: 1). R2 requires short circuit study every 24 months even though the SDT’s own rationale is that other requirements will trigger Protection System Studies first. Thus R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. 2). Please replace “detect Faults on the BES Transmission System” with “protect the BES Transmission System” in all three places it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17

Organization	Yes or No	Question 5 Comment
		already approved by the industry. 3). VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it “has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements.” Many entities have numerous Interconnected Elements, and recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity’s Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively. Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation. 4). Throughout the 1st and 2nd draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.1.1, R2.1.2, R2-2.2, R4-4.1, R4-4.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. We appreciate the Drafting Teams perspective, but the SERC PCS believes that such cross references are confusing. 5). Under R1 - MI measure wording does not read as a completed statement. Suggest removing ‘that’ from the first sentence. 6) The process chart is a direct indication that this process and undertaking for entities will be overwhelming. New systems will be required to track many details of timeframe requirements and communication dates. Additional resources will be required placing increased workload for an effort to change the process that already works for us when working with other entities. The Drafting Team indicated, ‘there is no evidence there is widespread miscoordination of protection systems.’

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **1. The drafting team does not see the direct correlation between the studies required in this Standard and the noted studies in the TPLs. Additionally, The drafting team believes that a 60 month period for subsequent studies may not identify incremental increases in fault currents that may impact Protection System operations.** **2. Figure 3 issue:** detect Faults on the BES Transmission System” with “protect the BES Transmission System” **3. VSL issue** **4. The format of this Standard has been approved through the NERC QR process as appropriate** **5. The suggested change has made** **6. statement but no suggested change**		
Idaho Power Co.	Yes	1. R1 The requirement is written to be applicable to Transmission Owners. In our case we have several lines where we do not own the Interconnecting Element, but operate the Protection System at one terminal. Based on the Glossary, we believe this makes us a Transmission Operator. If this interpretation is accurate, there would seem to be a gap in the Applicability of the Standard, as it does not include the Operator. 2. R2 We are wondering why this Requirement is only applicable to the Transmission Owner. Should it not be applicable to all the functional entities similar to the language used in R1, R3, and R4? General comments 3. In reviewing the Standard, there was confusion related to the Protection System Study and what the 10% was measured against. We believe that the Protection System Study referred to in the Standard is that group of faults and contingencies used to create the in-service settings of the relay. Could this be clarified? 4. Additionally, the exchange of information between Functional Entities is a

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>critical part of PRC-027, however, no mechanism is in place to ensure proper contact information is available. Employee movement within a utility may render contact information obsolete. In addition, Independent Power Producers, such as wind farms, are not typically staffed by local personnel or by individuals with a knowledge of System Protection. Because PRC-027 relies so heavily on the exchange of information it is not sufficient to simply place time lines on the transfer of data between Functional Entities. Additional controls to ensure that these data requests reach the appropriate people is needed.</td></tr>
<tr><td colspan="3">**Response: Thank you for your comment.**
1. Own protection systems but are not a transmission owner issue
2. As noted in the Guidelines and Technical Basis section: In Requirement R2, the Transmission Owner is identified as the Functional Entity responsible for performing the Fault current 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.
3. The intent is that the 10% be measured against the fault currents that were available at the interconnected bus at the time the last Protection System Coordination Study was done.
4. The drafting team agrees that entities must have accurate contact information for this standard as well as the existing requirements in PRC-001</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>Yes</td><td>We agree with the change.
However, we are adding a comment on the VRFs.
The VRFs should be High, not Medium. There are similar requirements in PRC-023-2 Transmission Relay Loadability, and TPL-001-2 Transmission System Planning Performance Requirements which have a High VRF.
Also, from the Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 - Protection System Coordination for Performance During Faults, the FERC VRF G4 Discussion reads “Guideline 4- Consistency with</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		NERC Definitions of VRFs: Failure to perform a Protection System Study for each Interconnected Facility to verify that Protection Systems coordinate such that the least number of power system Elements are isolated to clear Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF." Poor protection system coordination during a disturbance can create severe system conditions faster than Operators can respond to them, leading to system instability or a cascading failure. These circumstances are consistent with the NERC definition of a High VRF.
Response: Thank you for your comment. **VRF issue**		
Pepco Holdings Inc & Affiliates	Yes	We agree with this change. However, we have several other comments concerning this standard in addition to those expressed in response to Questions 1 thru 5. Usually there is a space on the comment form to enter these additional comments. Absent one, we offer these additional comments as an addendum to Question 5. 1) Requirement R2: The phrase "Facility associated with an" contained in R2 is confusing and unnecessary and should be eliminated. R2 should simply read "For each Interconnected Element on its System, the Transmission Owner shall:" 2) 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

Organization	Yes or No	Question 5 Comment
		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. 3) 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). 4) 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

Organization	Yes or No	Question 5 Comment
		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 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 we support the overall desire to ensure that protective systems are "properly coordinated"; we see 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, we believe PRC-027 goes well beyond what is was directed by FERC, and the stated purpose of the SAR. We urge the SDT to revisit FERC Order 693 and revise this standard as appropriate to address only the stated FERC directives.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team considered this alternative language but believes the existing language is sufficient.
2. The drafting team considered this alternative previously; however the “point of interconnection between the Entities’ can sometimes be at a given point on the line and in some cases the neither entity may own the line itself. Therefore the present language was deemed the best verbiage.
3. 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 I don’t see this as necessary?
4. FERC directives issue</td></tr>
<tr><td>Southern Company</td><td>Yes</td><td>1. We believe that the proposed standard is too prescriptive regarding the specific duties and multiple time frames of each of the parties TO,GO, and DP. Including time frames for each Interconnect Element with regard to effective dates (6 mo), initial studies (48 mo), studies triggered by change of equipment or change of fault current (6mo), TO/GO/DP agreed upon schedules (variable), delivery of studies (90 days) , short circuit studies (24 mo), notification to others of fault current changes (30 days), change detail notification (30 days), and review of summary results (90 days) is unnecessary and unduly burdensome. The process flow chart provided on page 22 of the draft standard is evidence of the complexity of the proposition. Please seriously consider the following simplified three-requirement approach which will similarly accomplish the desired outcome of coordination of the Protection System for Interconnected Elements.
R1). Require the two parties of the Interconnecting Element to jointly develop a Protection System Study- initially with X months to complete.
R2). Require a review/update of the protection system study for proper coordination anytime a change to the system may upset coordination.
R3). Require a review/update of the protection system study for proper</td></tr>
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Organization	Yes or No	Question 5 Comment
		coordination every X years. The corresponding measures for each proposed requirement could be... M1: has a protection system study been performed by the initial required date? M2: has a protection system study been reviewed/updated for system changes which impact the coordination? M3: has the protection system study been reviewed/updated every X years? During an audit period these requirements and measures will drive entities to establish and maintain protection system studies. This approach keeps the focus on the protection system study rather than the multiple actions with varying time frame restrictions. We believe that these changes will result in an equally effective driver to establish coordination while keeping the standard as succinct as possible. 2. In general, for protection on the transmission line leaving the plant, the generator owner should be responsible only for coordinating with the first set of line relaying encountered when proceding across the interconnecting element. He should not be responsible for coordinating with relaying at the opposite end of the interconnecting element. For example, in Figure 5 on Page 28 of the draft standard, Generator Owner T should not have to worry about a review of the relaying located at breakers G, F, or E. Another example is Figure 2, Page 25 of the draft standard: Generator Owner R should not be responsible for reviewing the relaying at the breaker C.
Response: Thank you for your comment. **1. The drafting team believes the present format is necessary to ensure the reliability objectives of the Standard are met.** **2. The drafting team agrees with your statement. Figure 5 is included for the unique situation that the owner of the interconnected bus may not be the owner of the protection systems.**		
Southwest Power Pool Reliability	Yes	

Organization	Yes or No	Question 5 Comment
Standards Development Team		
GP Strategies	Yes	
Luminant	Yes	
Hydro One Networks Inc.	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
JEA	Yes	
US Bureau of Reclamation	Yes	
Operational Compliance	Yes	
pacificorp	Yes	
Western Electricity Coordinating Council	Yes	
Dynegy	Yes	
American Transmssion Company, LLC	Yes	
Essential Power, LLC	Yes	
Wisconsin Electric Power Company	Yes	
Liberty Electric Power LLC	Yes	

Organization	Yes or No	Question 5 Comment
Public Service Enterprise Group	Yes	
Ameren	Yes	
Entergy Services, Inc. (Transmission)	Yes	
Exelon Corporation and its affiliates	Yes	
Cogentrix Energy Power Management, LLC	Yes	
Kansas City Power & Light	Yes	
City of Tallahassee	Yes	
NV Energy	Yes	
ATCO Electric		Additional comments from AE that does not fit any specific question: (1) Timelines: There are too many hard timelines that aren't consistent between individual requirements (24 months, 6 months, 90 days, 30 days, agreed upon time frame, prior to implementation, etc.). Keeping track of these timelines and evidence gathering will take considerable time and effort. Can the drafting team reduce the amount of timelines to make this standard manageable? Can the drafting team anticipate how to audit this standard during the standard development process? (2) There are requirements referred to other requirements and vice versa. Can the drafting team not to refer the requirements back and forth? Can the drafting team anticipate how to audit this standard during the standard development process?

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **1. The drafting team believes the present format including the timelines is necessary to ensure the reliability objectives of the Standard are met. The drafting team can't anticipate audit procedures; however, members of the drafting team will hopefully be involved in the development of the RSAW** **2. The drafting team can't anticipate audit procedures; however, members of the drafting team will hopefully be involved in the development of the RSAW**		
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: Thank you for your comment. Response: Thank you for your comment. Thank you for your support. **Al M to review and provide answer**		
Midwest Reliability Organization NERC Standards Review Forum		In addition to the previous comments outlined above, the NSRF offers the following comments for the drafting team's consideration. 1. Recommend the timeframes in R1.1.1 and R2.1 be stated in calendar years. The NSRF is concerned that a utility would be found in violation of this standard if one study was done in February of 2012 and the next one in March 2014 based on the current wording. The intent of a results-based standard is not to have these types of technicalities built into them.

Organization	Yes or No	Question 5 Comment
		2. An entity cannot study a part of the system that they do not own. The examples at the end of the draft in the Application Guidelines appear to imply that they should. Settings should be obtained from remote ends of a tie line only to be used in conjunction with studying the settings for which an entity has direct control. If an entity can't issue setting changes for a relay, then the entity can't study it to see what the settings should be. If both ends need adjustment then an iterative coordination back and forth between Entities should be performed. The majority of utilities would not feel comfortable accepting an external entity's settings changes for their own equipment. Recommend additional wording be added to the Application Guidelines to the further clarify the drafting team's intent. 3. R2, Part 2.1.1: Recommend R2, Part 2.1.1 be revised to only require short circuit values be 'studied' at buses for which the entity in question specifically owns. For Interconnected Facilities between two entities, fault current values should be 'requested' by the neighboring utility. This would be beneficial to ensure that both entities are comparing models to keep them as up to date as possible. Better yet are boundary equivalents as discussed in previous comments. 4. R2, Part 2.2: Similar to our previous comment for R1, Part 1.2, the proposed language in Part 2.2 appears to indicate that internal Interconnected Elements would require additional documentation and notification beyond what is necessary. This should only be required of Interconnected Elements in which there are two or more owners. Proof of study should be adequate for internal situations. 2.2 Within 30 calendar days after identification where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates a deviation in Fault current of 10% or greater, provide each owner of the Protection System associated with the Interconnected Element, that include two or more Registered Entities, the updated Fault current values (Iscs).

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **1. Calendars years vs months** **2. The drafting team does not see the issue that has been stated. Settings obtained from remote ends of a tie line would be used to ensure no coordination issues exist with other setting on its system. If some are identifies then the drafting team agrees that it may be an iterative process for the two entities to come to a mutual solution to the coordination issue identified.** **3. The drafting team believes that the R 2.1.1 indicates that the entity is conducting the study at their interconnected bus: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus.** **4. The drafting team believes that R 2.2 indicates that the entity is conducting only concerned values at their interconnected bus**		
PJM Interconnection		PJM supports revising the language in Requirement 1 of PRC-001 by replacing the term 'familiar.' This word is ambiguous and confusing in terms of the specific expectations of the applicable functional entities regarding the purpose and limitations of protection system schemes applied in its area.
Response: Thank you for your support		
ReliabilityFirst		ReliabilityFirst offers the following comments on the VSLs for consideration: 1. Requirement R3 VSL a. ReliabilityFirst believes VSL for Requirement R3 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement." Requirement R3, Part 3.1 and 3.1 requires the entity to provide "details" and the associated VSLs references "information". ReliabilityFirst recommends the SDT modify the VSL to be consistent with the language in the requirement. b. It is unclear which requirement the last VSL under the "Severe" category is

Organization	Yes or No	Question 5 Comment
		referring to. ReliabilityFirst recommends adding the Part number in which the VSL is associated with. 2. Requirement R4 VSL a. ReliabilityFirst believes VSL for Requirement R4, Part 4.1 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement." The VSLs associated with Part 4.1 use the language "confirmed acceptance" though the language in the actual Part talks about review of summary results and response as to whether further action is required. ReliabilityFirst recommends the SDT modify the VSL to be consistent with the language in the requirement as follows: "The responsible entity reviewed the summary results of a Protection System Study and responded as to whether further action is required per R4, Part 4.1, but was late by 10 calendar days or less"
Response: Thank you for your comment. **1. VSL issues** **2. VSL issues**		
Consumers Energy		The following comments are unrelated to Question 5. However, there has not been a question/section added for other/general comments. 1) In the process flow chart (page 22) the R2.2 box which states "Within 30 days, provide each owner of the Protection System associated with the Interconnected Element", we believe the key element, "the updated Fault current values" was not included in this statement. 2) In reading the Example Process on page 23, we were expecting to be able to follow it through the process flow chart on page 22 as one possible example to guide you through the standard process. As it started off as a request for information, we assumed the flow process started in the R3 box "Data request"

Organization	Yes or No	Question 5 Comment
		which indicates no further action. Yet the example process continues on. We would suggest an improved explanation paragraph be added to the "Example Process" to better clarify what the example is intended to illustrate.

Response: Thank you for your comment.

1. flow chart questions

2. flow chart questions

Additional Comments:

ATCO Electric (AE) – Requirement R1.1.2 – A 10% change in fault current isn't much in some areas of AE's system, perhaps as little as a few hundred amps. This could lead to a burdensome requirement to frequently review the same areas of our system. Ten percent seems fairly restrictive when we typically use safety margins of 40% to 50% in selecting instantaneous overcurrent settings

Response: Thank you for your comment.

As noted in the Guidelines and Technical Basis section: The drafting team investigated various inputs that would trigger a review of the existing Protection System Studies 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 Protection System Coordination Study may be necessary.

In the situation that you described, the Standard provides the entities the opportunity to 'technically justify why such a study is not required'

END OF REPORT