Meeting Notes

Project 2007-06 System Protection Coordination Standard Drafting Team

September 4-7, 2012

NERC Headquarters
Atlanta, GA

Administrative

1. **Introductions**

   The meeting was brought to order by Chair, Phil Winston at 8:00 a.m. ET on Tuesday, September 4, 2012. 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	
Samuel Francis	Oncor	Member	X	
Jeffery Iler	American Electric Power	Member	X	
William Waudby	Consumers Energy	Member	X	
Kevin Wempe	Kansas City Power & Light	Member	X	
Syed Ahmad	FERC	Observer		X
Tom Bradish	FERC	Observer	X	
Al McMeekin	NERC Staff	Member	X	
Willie Phillips	NERC Staff	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 6 of the 9 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 team roster and confirmed that it was accurate and up to date.

Agenda

1. **Discuss developments since last meeting**

   Mr. Winston reported on the progress by the subteams developing responses to stakeholder comments.

2. **Discuss Internal Controls concepts**

   Mr. McMeekin presented the concepts of Internal Controls to the team and led a discussion on how they may be applied to PRC-027-1.C.

3. **Continue responding to comments**

   The team completed responding to Questions 1, 2, 3, 4, 5, and 6 including the Summary of Comments. Responses to Questions 7 and 8 were also completed.

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

   The team made changes to the standard based on the stakeholder comments. Refer to end of meeting documents.

5. **Action Items**

   Mr. Winston made the following assignments to ensure completion of the response to comments document at the St. Louis meeting in October, 2012.

   Bill Middaugh's team – pages 184-218
   Sam Francis' team – pages 219-242
   Phil Waudby's team – pages 243-286

   Mr. McMeekin will prepare the summaries for Questions 7 and 8, and clean-up all documents.

6. **Future meeting(s)**

   St. Louis, October 16-18, 2012.

7. **Adjourn**

   The meeting adjourned at 12:00 p.m. ET on Friday, September 7, 2012.

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.

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 utilized to protect 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. 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
Post first draft of standard for 30-day Formal Comment Period.	May 2012
45-day Formal Comment Period with Parallel Initial Ballot	August 2012
30-day Formal Comment Period with Parallel Successive Ballot	November 2012

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is three months beyond the date that this standard is approved by applicable regulatory authorities, where such explicit approval is required. Where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter that is three months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise prescribed by the laws or regulations of the applicable ERO governmental authorities. For Facility interconnections 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. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the glossary.

Terms:

Interconnected ~~Facilities~~Elements: ~~BES~~ Elements~~Facilities~~ that ~~are~~ electrically join~~ed by one or more Element(s) and are owned by~~ ~~different~~ separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity~~functional, operating, or corporate entities.~~

Protection System 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 ~~Facilities~~Elements, such that the least number of power system Elements are isolated to clear Faults~~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~~.

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~~Protection Systems installed at Interconnected Facilities.~~

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 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."*

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 SDT for Project 2007-03 Real-time Operations, charged with revising the TOP group of reliability standards. The Project 2007-03 SDT 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-001-2, 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:

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]*

1.1. Perform a Protection System Study for each Interconnected ~~Facility~~ Element to coordinate Protection Systems, such that the least number of power system Elements are isolated to clear ~~to verify that Protection Systems remove from service only those Elements required to isolate Faults~~ Faults as follows:

1.1.1 Within ~~36~~ 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Facility exists ~~that was performed on or subsequent to June 18, 2007~~.

1.1.2 Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected ~~Facility~~Element, as described in Requirement R2, or technically justify ~~unless the entity can demonstrate~~ why such a study is not required.

1.1.3 When proposing or being notified of a change at the Interconnected Facility, as described in Requirement R3, Part 3.1 or Part 3.3, or technically justify why such a study is not required~~unless the entity can demonstrate such a study is not required~~.

1.2. Provide to each affected Interconnected ~~Facility~~ Element owner a summary of the results of each Protection System Study performed pursuant to this requirement,

Rationale for R1:

Part 1.1 Protection System Studies are necessary to verify coordination of Protection Systems for existing and new Interconnected Facilities. The SDT defines the term "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."

Part 1.1.1 ~~Protection System studies performed after June 18, 2007 (the effective date of PRC-001-1) and in accordance with PRC-001-1 are sufficient to meet Requirement R1, Part 1.1.1.~~ The SDT believes that ~~36~~ 48 months is an appropriate period of time for entities to perform the Protection System S~~s~~tudies required where no study exists. The SDT has no evidence there is widespread miscoordination between Interconnected Facilities that warrants a shorter time frame.

Part 1.1.2 The SDT 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, where such conditions may warrant a new Protection System Study, or to justify why no such study is needed, i.e., 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 SDT believes that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, or to justify why no such study is needed. The SDT believes that 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 requirement provides for the communication of the results of a Protection System Study to allow the interconnected owner to review the results. The SDT believes to properly ensure coordination of Protection Systems of Interconnected Facilities all entities need to assess the study results. The SDT believes that 90 calendar days is a reasonable time for the entity to provide the results of the Protection System Study performed in accordance with Requirement R1 to the Interconnected Facility owner.

(including, at a minimum, the ~~Protection~~ protective ~~System~~relay ~~(s)~~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.

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, or the summary results of each Protection System Study (either in hard copy or electronic file formats) and meeting the time frames specified in Parts 1.1.1. and 1.1.2. Acceptable evidence of technical justification for not performing a Protection System Study ~~, or documentation~~ as specified in Parts 1.1.2 and 1.1.3 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.~~demonstrating why a study is not required for changes described in Parts 1.1.2. and 1.1.3.~~

M2. Acceptable evidence for Requirement R1, Part 1.2. is dated documentation demonstrating each affected entity received, within the specified time frame, the summary results of each Protection System Study (hard copy or electronic file formats) sent, pursuant to Requirement R1, Part 1.2.

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

2.1. Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus, not less than once every 24 months~~Perform a short circuit study to determine the present Fault current values, not less than once every 24 months~~.

2.2. Calculate the percent deviation between the Fault current values (single line to ground and 3-phase for the interconnecting bus(s) ~~or Element(s)~~ under consideration) 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:

$$\%\ Deviation = \left|\frac{Iscs - Ipss}{Ipss}\right| \cancel{\left(\frac{Vscs - Vpss}{Vpss}\right)} x\ 100$$

Where: I~~V~~$_{scs}$ ~~= Fault~~= Fault current value from present short circuit study

And: I~~V~~$_{pss}$ ~~= Fault~~= Fault current value used in the most recent Protection System Study

Rationale for R2: This requires a periodic review of Fault currents and notification 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 Fault current studies because they maintain the data necessary to perform the studies. The SDT determined that 10% was an appropriate point at which to require notification, based on the fact that Protection System elements that can be affected by Fault current are typically set with margins above 10%.

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. The SDT believes studies associated with changes that would affect the coordination in less time would be triggered by other requirements in this standard.

Part 2.2 The SDT is requiring this formula to assure a consistent approach is used by each Transmission Owner when calculating the percent deviation in Fault current vales.

Part 2.3 The SDT believes the 30-day time frame is reasonable for sending notification(s) to the interconnected entity(s).

2.3. Where the calculation performed, pursuant to Requirement R2, Part 2.2, indicates a deviation in Fault current of 10% or greater, notify each owner of the Interconnected ~~Facility~~Element, at which the 10% or greater deviation applies, within 30 calendar days after identification.

M3. Acceptable evidence for R2, Part 2.1 is dated documentation (hard copy or electronic file formats) containing the present Fault current values from the short circuit study for each Interconnected Facility analyzed.

M4. Acceptable evidence for R2, Part 2.2 is dated documentation (hard copy or electronic file formats) that identifies the percent deviation from the most recent Protection System Study Fault current values determined by the formula pursuant to Part 2.2.

M5. Acceptable evidence for R2, Part 2.3 is documentation (hardcopy or electronic file formats) demonstrating identification of a deviation in Fault current values 10% or greater, along with documentation (hard copy or electronic file formats) demonstrating each affected entity received notification of such within the specified timeframe.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide ~~to each Transmission Owner, Generator Owner, and Distribution Provider the details (e.g., project schedule, protective relaying scheme types and settings) as follows~~to each Responsible Entity connected to the same Interconnected Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

3.1. Details (e.g., project schedule, protective relaying scheme types and settings) ~~F~~for any change or additions listed below; either at an existing or new Interconnected Element~~Facility~~;~~,~~ or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Element~~Facilitie~~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 changes any sequence or mutual coupling impedance ~~line lengths and/or conductor size or spacing~~

Rationale for R3: This requires the transfer of appropriate information to the entities of each Interconnected Facility 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 Interconnected Facility owner(s) in a timely manner. The SDT 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 change in impedance 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 requested information from an interconnected owner in a timely manner in order to perform a Protection System Study, as required in Parts 1.1.1, 1.1.2, 1.1.3. The SDT 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 SDT believes 30 calendar days

- ~~Additions, removals, or replacements of transmission system Element(s)~~
- Changes to generator unit(s) that result in a change in impedance~~, including replacements, re-ratings, and impedances~~
- Changes to ~~Replacement of~~ the generator step-up transformer(s) that result in a change in impedance

3.2. Requested information related to the coordination of Protection Systems of an Interconnected Element within 30 calendar days of receiving a request or a~~A~~ccording to an agreed-upon schedule~~ with a Transmission Owner, Generator Owner, or Distribution Provider, or absent such an agreement, within 30 calendar days of receiving a request for information~~.

~~**3.2.**~~**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.

~~**3.3.** Within 30 calendar days after:~~

~~**3.3.1** Corrections are made when Protection System errors are found during Misoperation investigations, commissioning, or maintenance activities.~~

~~**3.3.2** Emergency replacements are made due to failures of Protection System components.~~

M6. Acceptable evidence for R3, Part 3.1 is documentation (hard copy or electronic file formats) demonstrating each affected entity received project details for the changes identified in the bulleted list. Evidence may include, but is not limited to, a summary of the future project or technical specifications of the proposed changes.

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

M8. Acceptable evidence for R3, Part 3.3~~, Part 3.3 and its subparts~~ is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the changes made ~~pursuant to Parts 3.3.1 and 3.3.2.~~ was ~~received~~ 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, review~~confirm~~ ~~agreement with~~ the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond whether further action is required. ~~.~~

Rationale for R4: This requirement ensures owners of Interconnected Facilities confirm that the Protection System(s) applied on each of its Interconnected Facilities is acceptable per the conditions identified in Parts 4.1, 4.2, and 4.3.

Part 4.1 The SDT 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~~resolve differences and reach agreement~~. If any issues are identified that require changes then Requirement R3 must be followed.

Part 4.2 The SDT believes that proposed modifications (including project schedules) to Interconnected Facilities, as described in Requirement R3, Part 3.1, must be communicated and agreed to prior to the in-service date. Agreement assures that the coordination of Protection Systems for Interconnected Facilities is achieved.

4.2. Prior to ~~the in-service date~~implementing ~~of~~ any planned change(s) ~~at the Interconnected Facility~~associated with Requirement R3, Part 3.1, confirm that the affected Interconnected Element~~Facility~~ owner(s) agree with any resulting ~~the~~ Protection System(s) changes~~, as described in Requirement R3, Part 3.1~~.

~~**4.3.** Within 30 calendar days after receipt:~~

~~**4.3.1** Confirm the Protection System(s) changes are acceptable pursuant to notification received per Requirement R3, Part 3.3.1.~~

~~**4.3.2** Confirm the Protection System(s) changes are acceptable pursuant to notification received per Requirement R3, Part 3.3.2.~~

M9. Acceptable evidence for R4, Part~~s~~ 4.1 is ~~, 4.2, and 4.3 is~~ dated documentation (hardcopy or electronic file formats) demonstrating that response was provided ~~confirmation was achieved~~ within the ~~respective~~ time frame~~(s)~~.

~~**M9.**~~**M10.** 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.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity; or if the Responsible Entity is owned, operated or controlled by the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e., another Regional Entity) to be responsible for compliance enforcement.

1.2. Evidence Retention

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

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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The responsible entity failed to perform a Protection System Study on an Interconnected Facility per R1, Parts 1.1.1, 1.1.2, or 1.1.3, or document why a study was not required. OR The responsible entity failed to provide Protection System Study results in accordance with R1, Part 1.2.
R2	Long-term Planning	Medium	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.	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 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 40 calendar days but less than or equal to 50 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 50 calendar days. OR The Transmission Owner failed to perform a short circuit study, as described in R2, Part 2.1. OR The Transmission Owner failed to calculate the percent deviation between the Fault currents, according to the formula designated in

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	R2, Part 2.2. OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by more than 30 calendar days. OR The Transmission Owner failed to notify the Interconnected Facility owner of the changes in Fault currents.
R3	Operations Planning	Medium	The responsible entity provided the requested information per R3, Part 3.2, 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.	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.	The responsible entity failed to provide information to the owners of the Interconnected Facilities 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.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The responsible entity provided the required information identified in R3, Part 3.3, 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 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 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 30 calendar days. OR The responsible entity failed to provide the requested information.
R4	Operations Planning	Medium	The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by 10 calendar days or less.	The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 30 calendar days. OR The responsible entity failed to confirm agreement with the summary results of the Protection System Study per R4, Part 4.1. OR The responsible entity failed to confirm acceptance of the planned changes pursuant to R4, Part 4.2

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by 10 calendar days or less.	OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	prior to implementation of those changes. OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 30 calendar days. OR The responsible entity failed to respond to the confirmation request per R4, Part 4.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

This requirement directs the performance of Protection System Studies for every Interconnected Facility to verify coordination of existing Protection Systems where no recent study exists or when Facility configuration or Fault current deviations of 10% or more have occurred. In developing the language to define Protection System 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 SDT defined the term Protection System 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 SDT believes applicable entities should have a documented Protection System Study for each Interconnected Facility to validate the Protection Systems perform in a manner consistent with the purpose of this Standard. Additionally, the SDT believes that 36 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 SDT also has no evidence there is widespread miscoordination between Interconnected Facilities 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.

It should be noted that Protection System studies performed after June 18, 2007 (the effective date of PRC-001-1) are sufficient to meet Requirement R1.

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 in Fault current, the notified entities must perform a new Protection System Study of the Interconnected Facility or document why a study is not required. The SDT recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater deviation in Fault current may not necessitate a new Protection System Study be performed; therefore this part of the requirement includes the statement, "… unless the entity can demonstrate that such a study is not required." The SDT 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 an Interconnected Facility, entities must perform a new Protection System Study, or document why a study is not required. The SDT 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 be performed; therefore this part of the requirement includes the statement, "… unless the entity can demonstrate that such a study is not required." 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. This is because the SDT 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 requires the entity performing the Protection System Study to provide a summary of the study results to the affected owners of Protection Systems applied at Interconnected Facilities. As guidance, the SDT lists the following inputs and results of a Protection System Study that may be included in the summary provided pursuant to this requirement:

1. 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 Interconnected Facility under study.
2. A 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.

3. A listing of any issues associated with the relay settings of the other owner(s) at the Interconnected 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 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. These variations could result from the accumulation of incremental changes over time. This requirement mandates a periodic review of Fault currents and includes the calculation of the percent deviation between the Fault current values used in the most recent Protection System 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 2.3.

Polling of SDT membership and various protection engineering committees indicates that short circuit databases are customarily updated annually. Based on this information, the SDT believes that requiring a 24-month periodic review of Fault currents provides entities additional flexibility to schedule and perform these studies and calculate the percent deviation, as described in Requirement R2, Part 2.2. The SDT believes studies associated with changes that would affect the coordination in less than 24 months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.3 further directs the Transmission Owner to, within 30 calendar days, inform Interconnected Facility owners when short circuit studies indicate that 10% deviations in Fault current have occurred at the Interconnected Facility. The SDT believes the 30-day time frame associated with this requirement is reasonable for sending notification to the interconnected entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the functional entity responsible for performing the 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 requires the Interconnected Facility owners to evaluate the impact to their Protection Systems due to proposed changes by requiring the registered functional entity initiating the changes to provide the details to the other affected entities of the Interconnected Facility. 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 SDT recognizes that Facility changes at other locations can impact the Protection System Study of the Interconnected Facilities; e.g., the addition of a large autotransformer bank or generator not directly associated with the Interconnected Facilities. 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,” 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 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 SDT 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: (1) Protection System errors are found during misoperation investigations, commissioning, or maintenance activities; (2) Emergency replacements are made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the SDT 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:

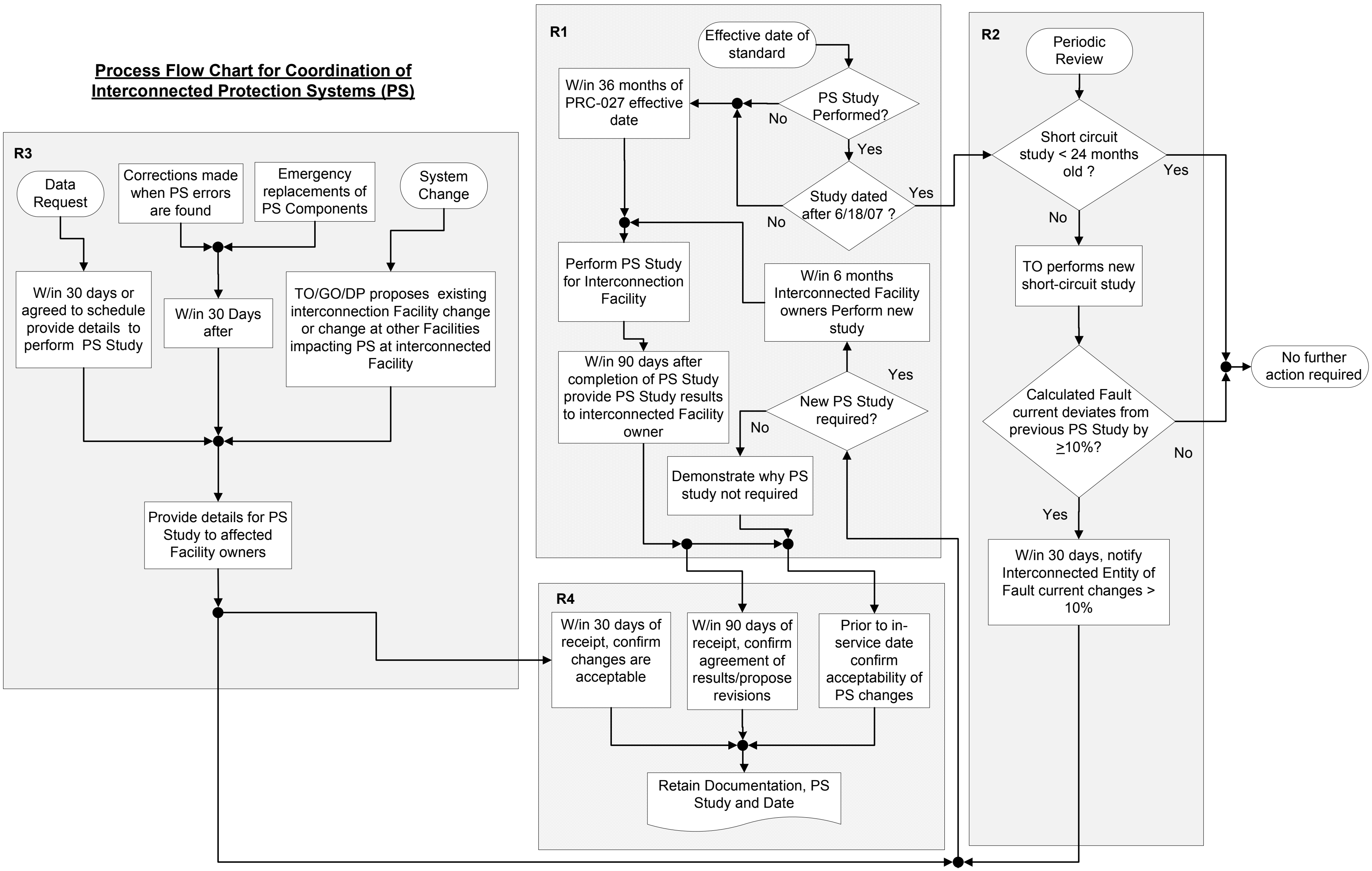
The reliability objective of this requirement is to bring the process of Protection System coordination full circle by gaining the confirmation of interconnected entities that their Protection Systems are coordinated consistent with the purpose of this standard. Cooperative participation of Interconnected 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 confirm agreement with the summary results of a Protection System Study, as described in Requirement R1, Part 1.2; or absent such agreement, propose revisions to achieve acceptable results. The SDT believes 90 calendar days after receipt of the results of a Protection System Study provides a reasonable time for the owners of Interconnected Facilities to resolve differences and reach agreement 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 Interconnected Facilities have been considered by all affected entities.

Requirement R4, Parts 4.3.1 and 4.3.2 direct confirmation within 30 calendar days that changes are acceptable when corrections are made due to Protection System errors found during misoperation investigations, commissioning, or maintenance activities, or when Emergency replacements are made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the SDT believes 30 calendar days provides adequate time for achieving such agreement.

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



Example Process

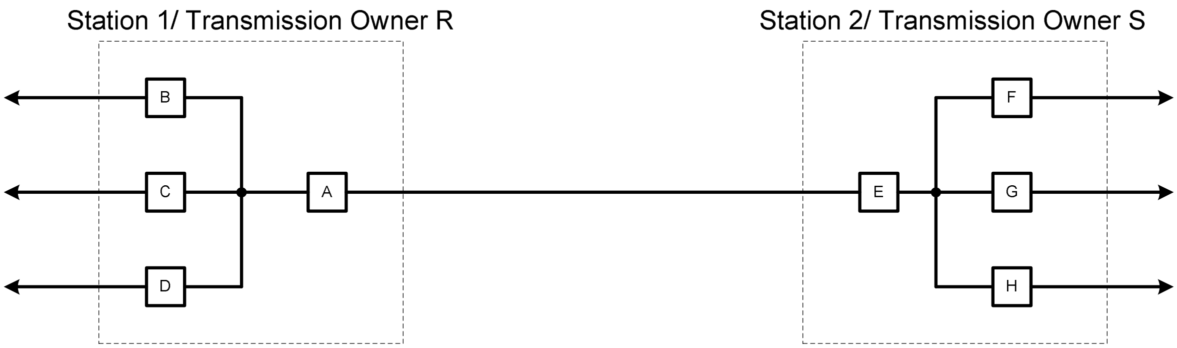
An example of the interaction between entities required to gather the information to perform an accurate study is below.

- 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 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.
- 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

Introduction: The diagrams below are intended to provide guidance related to the responsibilities associated with the purpose of this standard between owners of Interconnected Facilities. 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.

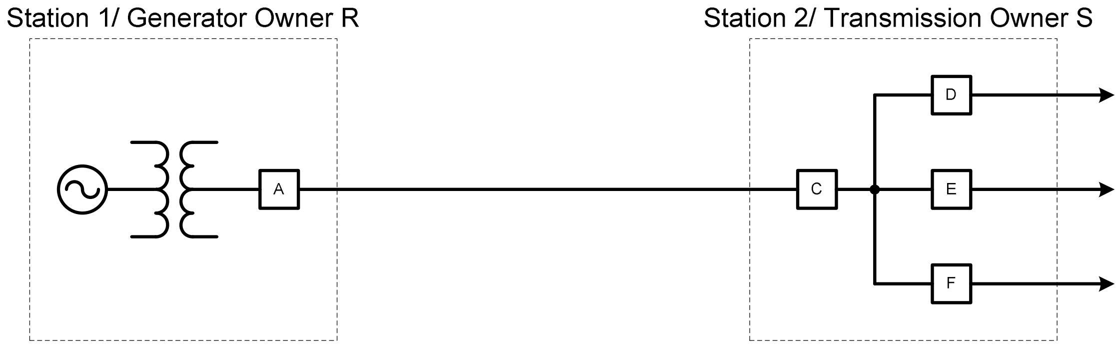
Figure 1



In Figure 1 above, the I~~i~~nterconnected~~ing~~ Element between the Transmission Owners ~~Interconnected Facilities (Station 1 – Transmission Owner R and Station 2 – Transmission Owner S)~~ is the transmission line between Breakers A and E.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 1, the responsibility for Owner S is to verify that the Protection System settings associated with Breaker A (provided by Owner R) do not result in coordination issues with the Protection System settings associated with Breakers E, F, G, and H. Likewise, the responsibility for Owner R is to verify that the Protection System settings associated with Breaker E (provided by Owner S) do not result in coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

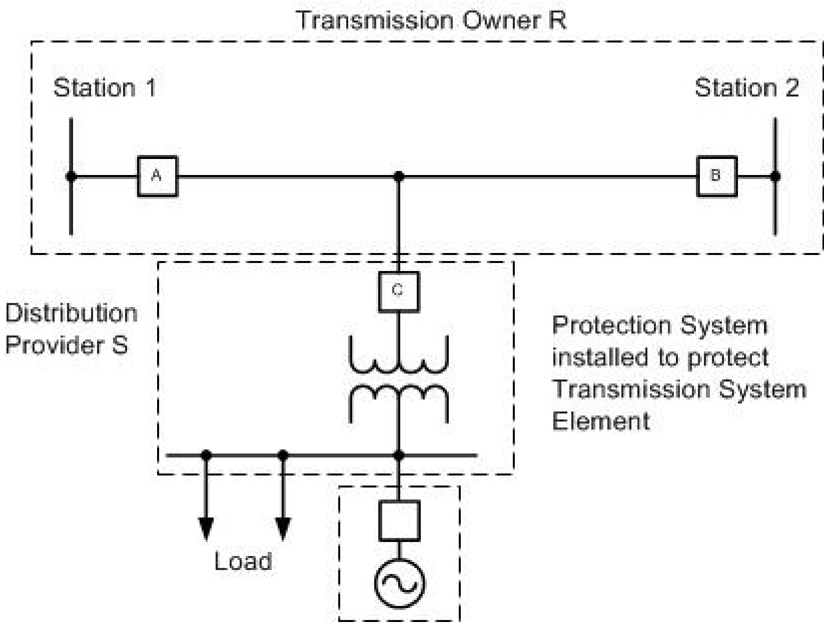
Figure 2



In Figure 2 above, the interconnecting Element between the Transmission to Generation Interconnected Facilities (Station 1 – Generation Owner R and Station 2 – Transmission Owner S) is the transmission line or bus between Breakers A and C.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 2, the responsibility for Transmission Owner S is to verify that the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems do not result in coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, the responsibility for Generation Owner R is to verify that the Protection System settings associated with Breaker C (provided by Owner S) do not result in coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3[am1]

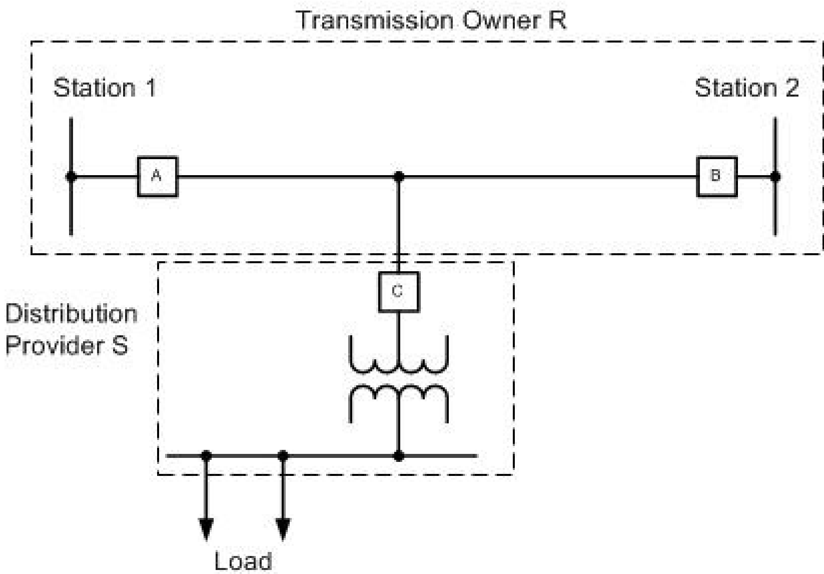


In Figure 3 above, the interconnecting Element between the Transmission Owner to Distribution Provider (with a generator) Interconnected Facilities (Transmission Owner R line between Breakers A and B – Distribution Provider S) is the transmission line or tap between the line and Breaker C.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 3, the responsibility for Transmission Owner R is to verify that the Protection System settings associated with Line Breaker C (provided by Distribution Provider S) and the generator Protection Systems do not result in coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2. Likewise, the responsibility for Distribution Provider S is to verify that the Protection System settings associated with Breakers A and B (provided by Owner R) do not result in coordination issues with the Protection System settings associated with Breaker C and the generator Protection Systems. In order to perform this verification, it will be necessary that the Generator Owner provide Distribution Provider S with its generator Protection System settings.

Note: 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 protect BES transmission system Elements.

Figure 4

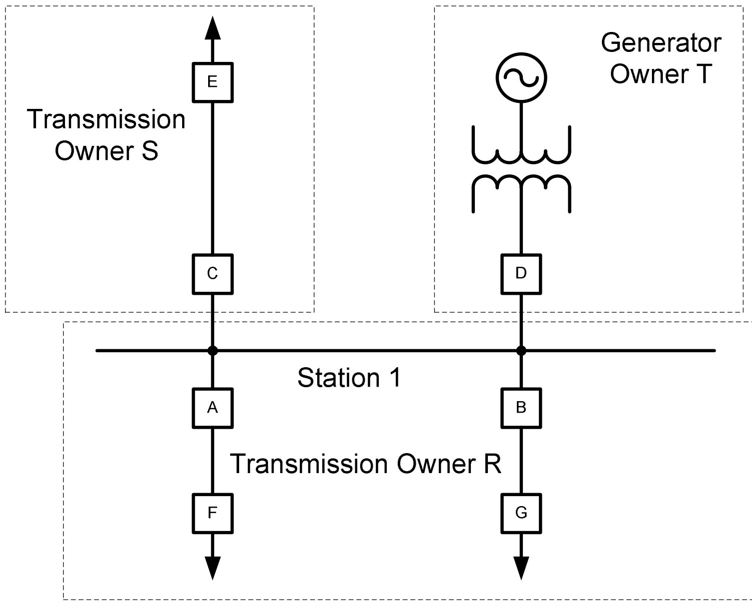


In Figure 4 above, the interconnecting Element between the Transmission Owner to Distribution Provider Interconnected Facilities (Transmission Owner R line between Breakers A and B – Distribution Provider S) is the transmission line or tap between the line and Breaker C.

Note: No specific Protection System 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.

Figure 5

Transmission/Generation Facility with Multiple Owners



In Figure 5 above, the interconnecting 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 associated with the Facilities in Figure 5:

The responsibility for Owner R is to verify that the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S or T) do not result in coordination issues with the Protection System settings associated with Breakers A, B.

The responsibility for Owner S is to verify that the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R or T) do not result in coordination issues with the Protection System settings associated with Breaker C. To perform this verification, 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.

The responsibility for Owner T is to verify that the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R or S) do not result in 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 verification, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

Consideration of Comments

System Protection Coordination - Project 2007-06

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 of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

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

	Additional Member	Additional Organization	Region	Segment Selection
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	

	Group/Individual	Commenter	Organization	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

	Group/Individual	Commenter	Organization	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

	Group/Individual	Commenter	Organization	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

				1	2	3	4	5	6	7	8	9	10
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

				1	2	3	4	5	6	7	8	9	10
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	

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

12. David Greene	SERC	SERC	
13. Joe Spencer	SERC	SERC	

				1	2	3	4	5	6	7	8	9	10
17.	Group	Jennifer Eckels	Colorado Springs Utilities	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Paul Morland		WECC	1
2. Charles Morgan		WECC	3
3. Lisa Rosintoski		WECC	6

				1	2	3	4	5	6	7	8	9	10
18.	Group	Charles Yeung	ISO RTO Council SRC		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Gary DeShazo	CAISO	WECC	
2. Steve Myers	ERCOT	ERCOT	
3. Matt Goldberg	ISONE	NPCC	
4. Bill Phillips	MISO	MRO	
5. Greg Campoli	NYISO	NPCC	
6. Stephanie Monzon	PJM	RFC	
7. Don Weaver	NBSO	NPCC	
8. Ken Gardner	AESO	WECC	

				1	2	3	4	5	6	7	8	9	10
19.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

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

				1	2	3	4	5	6	7	8	9	10
20.	Group	Mary Jo Cooper	GP Strategies	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Elizabeth Kirkley	City of Lodi	WECC	3
2. Angela Kimmey	Pasadena Water and Power	WECC	1, 3
3. Douglas Dreager	Alameda Municipal Power	WECC	3
4. Ken Dizes	Salmon River Electric Co-op	WECC	1, 3
5. Sam Rohn	California Pacific Electric Co.	WECC	3
6. Colin Murphey	City of Ukiah	WECC	3
7. Michael Knott	Granite State Electric	NPCC	3

				1	2	3	4	5	6	7	8	9	10
21.	Group	David Dockery	Associated Electric Cooperative, Inc.,	X		X		X	X				

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

				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

				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

				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 phase '"… 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.

Organization	Yes or No	Question 1 Comment
		a. 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- 027-1, 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.

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 SDT agrees that the use of the term 'coordination' in PRC-001 did result in multiple meanings and potential confusion. The SDT 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

Organization	Yes or No	Question 1 Comment
specified within requirements established in other approved NERC Reliability Standards.”		
Southwest Power Pool NERC Reliability Standards Development Team	No	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 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

Organization	Yes or No	Question 1 Comment
		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 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: PURPOSE HERE 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 SDT revised**

Organization	Yes or No	Question 1 Comment
Applicability Section 4.2 as follows: Protection Systems installed at Interconnected Stations for the primary function of detecting Faults on BES Elements. Additionally, the SDT changed the term "Interconnected Facilities" to Interconnected Elements" defined as follows: INTERCONNECTED ELEMENTS HERE.		
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

Organization	Yes or No	Question 1 Comment
		standards or at least group of standards the SDT is referring to.
Response: Thank you for your comment. 1. **As noted in the Background information section, the SDT 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 SDT 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: PURPOSE HERE**		
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