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

October 16-18, 2012

Ameren Headquarters
St. Louis, MO

Administrative

1. **Introductions**

   The meeting was brought to order by Chair, Phil Winston at 8:00 a.m. CT on Tuesday, October 16, 2012. Building and safety information/logistics were provided by Paul Nauret of Ameren. Each participant was introduced; Those in attendance were:

Name	Company	Member/ Observer	In Person	Conference Call/Web
Philip Winston, Chair	Southern Company	Member	X	
Bill Middaugh, Vice Chair	Tri-State G & T Association, Inc.	Member	X	
David Cirka	National Grid	Member		X
Samuel Francis	Oncor	Member	X	
William Waudby	Consumers Energy	Member	X	
Kevin Wempe	Kansas City Power & Light	Member	X	
Syed Ahmad	FERC	Observer		X
Tom Bradish	FERC	Observer	X	
Al McMeekin	NERC Staff	Member	X	
Paul Nauret	Ameren	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 roster and confirmed that it was accurate and up to date.

Agenda

1. **Discuss developments since last meeting**

   Mr. Winston informed the team of the continued work performed on the documents since the September 2012 meeting.

2. **Discuss Internal Controls concepts**

   No discussion of Internal Controls was held.

3. **Continue responding to comments**

   The three subteams presented their draft responses to Question 9 for the team's approval. This completed the responses to comments.

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

   The SDT reviewed each document to ensure all changes were consistent throughout. Refer to the attached documents for specifics.

   The SDT developed the posting questions to focus on the major changes made to the standard based on the stakeholder comments. They included: 1) revising the Purpose statement; 2) revising the two definitions – Interconnected Element and Protection System Study; 3) modifying the timeframe in Requirement R1 to 48 months; 4) replacing the need to "reach agreement" with "confirming acceptance". In Requirement R4; and 5) modifying the requirements and measures to indicate that information was "provided" instead of "demonstrating that each affected entity received notification".

5. **Next steps**

   Mr. McMeekin will complete the preparation of all documents and submit them for Quality Review as quickly as possible to achieve a a mid-November 2012 posting.

6. **Future meeting(s)**

   The SDT held several weeks open in January 2013 for potential meetings based on the standard being posted during November 2012 for a 30-day period.

7. **Adjourn**

   The SDT thanked Ameren for its hospitality and the Chair adjourned the meeting at 4:00 p.m. CT on Thursday, October 18, 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.
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 ~~utilized to protect~~for Interconnected ~~Facilities~~Elements, such that ~~those Protection Systems remove from service only those Elements required to isolate Faults, while meeting~~ the least number of power system ~~performance specified within requirements established in other approved NERC Reliability Standards~~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
~~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
30-day Formal Comment Period with Parallel Successive Ballot	March 2013
30-day Formal Comment Period with Parallel Successive Ballot	June 2013
Recirculation Ballot	July 2013

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is ~~three~~six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where ~~such explicit approval is required. Where no~~ regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is ~~three~~six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise ~~prescribed by~~made effective pursuant to the laws ~~or regulations of the~~ applicable to such ERO governmental authorities. For ~~Facility interconnections~~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. ~~*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.*~~

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 ~~Facilities~~~~: BES Facilities~~**Element**: An Element that ~~are~~ electrically ~~joined by one or more Element(s) and~~ joins separate Functional Entities, including those Functional Entities that are ~~owned by different functional, operating, or corporate entities.~~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.

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, 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~~Elements, such that the least number of power system Elements are isolated to clear 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 ~~at~~for the purpose of detecting Faults on Interconnected ~~Facilities.~~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.~~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 ~~was developed in the results-based format and~~ 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 ~~contains~~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~~drafting team for Project 2007-03 Real-time Operations, charged with revising the TOP group of ~~Reliability Standards.~~reliability standards. The Project 2007-03 ~~SDT is recommending retirement of~~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 ~~the training aspects of PRC-001-1,~~ Requirement R1 ~~be~~remain in PRC-001-3, until its reliability objective is addressed ~~in Reliability Standard PER-005-1 with~~by either a revision to ~~its Applicability section to include the Generator Operator~~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~~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

> **Rationale for R1:**
>
> Part 1.1 Protection System Studies are necessary to verify coordination of Protection Systems for existing and new Interconnected ~~Facilities.~~Element. The ~~SDT~~drafting team defines the term "Interconnected ~~Facilities~~Element" as "~~BES Facilities~~An Element that ~~are~~ electrically ~~joined by one or more Element(s) and are owned by different functional, operating, or corporate entities~~joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity."
>
> 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~~drafting team believes ~~that 36~~48 months is an appropriate period of time for entities to perform the ~~studies~~Protection System Studies required where no study exists. The ~~SDT~~drafting team has no evidence there is widespread miscoordination ~~between~~ of Protection Systems associated with Interconnected ~~Facilities~~Elements that warrants a shorter time~~-~~ frame.
>
> Part 1.1.2 The ~~SDT~~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~~Fault current deviation at an interconnecting bus, where such conditions may warrant a new Protection System Study, or to technically justify why no such study is ~~needed~~required, i.e., when a line is protected by dual current differential systems with no backup elements set that are dependent upon ~~fault~~Fault current.
>
> Part 1.1.3 The ~~SDT~~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 ~~SDT~~drafting team 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~~

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 on its System, to ~~verify that~~coordinate Protection Systems ~~remove from service only those~~, such that the least number of power system Elements ~~required~~are isolated to ~~isolate~~clear 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~~Element exists.

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

1.2. Provide to ~~each affected Interconnected Facility~~ 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 ~~Protection System(s)~~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.

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 ~~timeframes~~time frames specified in Parts 1.1.1. and 1.1.2~~., or documentation demonstrating why a study is not required~~. Acceptable evidence of technical justification for ~~changes described~~not performing a Protection System Study 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.

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

M2. ~~For each~~ the owner(s) of the Protection System(s) associated with the Interconnected ~~Facility, each~~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. ~~Perform~~At least once every 24 months, perform a short~~-~~circuit study to determine the present ~~fault current values, not less than once every twenty-four months~~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.

2.2. Calculate the percent deviation between the ~~fault~~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

Rationale for R2: This
currents at the interconnec
to the applicable entities w
Requirement R2 criteria.
Facility owners are kept a
proper performance of the
Transmission Owner is ide
performing the short circu
data necessary to perform
determined that 10% was
information based on the
typically set with margins

Part 2.1 Short circuit datal
annually, so the drafting te
entities flexibility to sched
studies and calculate the p
believes studies associated
coordination in less time v
requirements in this standa

Part 2.2The drafting team
consistent approach is use
calculating the percent dev

Part 2.3The drafting team
reasonable for providing t
owner(s) of the Protection
Interconnected Element.

~~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).~~

System Study and the ~~fault~~Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation:

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

$$\% \ Deviation = \left|\frac{Iscs - Ipss}{Ipss}\right| x\ 100$$

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

And: ~~V_{pss} =~~ I_{pss} = Fault current value used in the most recent Protection System Study

2.3. Where the calculation performed, pursuant to Requirement R2, Part 2.2, indicates a deviation in ~~fault~~Fault current of 10% or greater, ~~notify~~provide each owner of the Protection System associated with the Interconnected ~~Facility at which the 10% or greater deviation applies,~~Element the updated Fault current values (I_{scs}), 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~~Fault current values from the short-circuit study for each ~~Interconnected Facility~~interconnecting bus 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~~Fault current values determined by the formula pursuant to Part 2.2.

Rationale for R3: This requires the transfer of appropriate information to the entities ~~of~~associated with each Interconnected ~~Facility~~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 ~~Facility owner(s) in a timely manner.~~Element(s). The ~~SDT~~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 ~~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, and 1.1.3. The ~~SDT~~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.

M5. Acceptable evidence ~~for R2, Part 2.3 is documentation (hardcopy or electronic file formats) demonstrating identification of a deviation in fault~~that the updated Fault current values ~~10% or greater~~(I_{scs}), along with documentation (hard copy or electronic file formats) ~~demonstrating each affected entity received notification of such~~for R2, Part 2.3 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~~Responsible Entity connected to ~~each Interconnected Facility, the~~

~~details~~the same Interconnected Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

~~**R3.**~~ Details (e.g., project schedule, protective relaying scheme types and settings) ~~as follows: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

3.1. ~~For~~for any change or additions listed below; either at an existing or new Facility associated with the Interconnected ~~Facility,~~Element; or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems ~~of~~associated with the Interconnected ~~Facilities.~~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 ~~line lengths and/or conductor size or spacing~~
- ~~Additions, removals, or replacements of~~ a transmission system Element~~(s)~~ that change any sequence or mutual coupling impedance
- Changes to generator unit(s) ~~including replacements, re-ratings, and impedances~~that result in a change in impedance
- ~~Replacement of~~ Changes to the generator step-up transformer(s) that result in a change in impedance

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

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

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

~~**3.4.**~~**3.3.** ~~Emergency~~, or 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~~Acceptable evidence may include, but is not limited to, a summary of the future project or technical specifications of the proposed changes (hard copy or electronic file formats) as identified in the bulleted list for R3, Part 3.1 were provided to each Responsible Entity connected to the same Interconnected Element.

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

M8. Acceptable evidence for R3, 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~~was provided within 30 calendar days.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

> Rationale for R4: This requirement ensures ~~owners~~owner(s) of Protection System(s) associated with Interconnected ~~Facilities~~Elements confirm that the Protection System(s) applied ~~on each of its Interconnected Facilities is~~are acceptable per the conditions identified in Parts 4.1~~, 4.2,~~ and 4.~~3~~2.
>
> Part 4.~~1 The SDT~~1The drafting team believes ~~ninety (~~90~~)~~ calendar days is a reasonable time for the ~~owners~~owner(s) of Protection System(s) associated with Interconnected Elements to review the summary results of ~~existing Interconnected Facilities to resolve differences and reach agreement~~a Protection System Study. If any issues are identified that require changes then respond whether further action is required.
>
> Part 4.2 The ~~SDT~~drafting team believes that proposed modifications (including project schedules) to Facility changes associated with the Interconnected ~~Facilities~~Element, as described in Requirement R3, Part 3.1, must be communicated and ~~agreed~~ ~~to~~accepted prior to the in-service date

4.1. Within 90 calendar days after receipt, ~~confirm agreement with~~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.

~~**4.2.**~~ Prior to ~~the in-service date of~~ implementing any planned change ~~at the Interconnected Facility, confirm the affected Interconnected Facility owners agree~~(s) associated with ~~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.~~

~~**4.4.**~~**4.2.** ~~Confirm the~~, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes~~ are acceptable pursuant to notification received per Requirement R3, Part 3.3.2~~.

M9. Acceptable evidence for R4, ~~Parts~~Part 4.1~~, 4.2, and 4.3~~ 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.**~~**M10.** Acceptable evidence for R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that confirmation of acceptance was achieved ~~within the respective timeframe(s).~~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 ~~M1through~~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 ~~Facility~~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 on an Interconnected ~~Facility~~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 ~~on~~at an ~~Interconnected Facility~~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 ~~10~~30 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~~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 ~~on~~at an ~~Interconnected Facility~~interconnecting bus per R1, Part 1.1.2, or documented why a study was not required, but was late by more than ~~10~~30 calendar days but less than or equal to ~~20~~60 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	The responsible entity performed a Protection System Study ~~on~~at an ~~Interconnected Facility~~interconnecting bus per R1, Part 1.1.2, or documented why a study was not required, but was late by more than ~~20~~60 calendar days but less than or equal to ~~30~~90 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~~at an ~~Interconnected Facility~~interconnecting bus per R1, Part 1.1.2, or documented why a study was not required but was late by more than ~~30~~90 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
				20 calendar days.		The responsible entity failed to perform a Protection System Study on an Interconnected ~~Facility~~Element 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~~Fault

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner ~~notified~~provided the owner(s) of the Facility associated with the Interconnected ~~Facility owner of~~Element the changes in ~~fault~~Fault currents, as described in R2, Part 2.3, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner ~~notified~~provided the owner(s) of the Facility associated with the Interconnected ~~Facility owner of~~Element the changes in ~~fault~~Fault currents, as described in R2, Part 2.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner ~~notified~~provided the owner(s) of the Facility associated with the Interconnected ~~Facility owner of~~Element the changes in ~~fault~~Fault currents, as described in R2, Part 2.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	currents, according to the formula designated in R2, Part 2.2. OR The Transmission Owner ~~notified~~provided the owner(s) of the Facility associated with the Interconnected ~~Facility owner of~~Element the changes in ~~fault~~Fault currents, as described in R2, Part 2.3, but was late by more than 30 calendar days. OR The Transmission Owner failed to ~~notify~~provided the owner(s) of the Facility associated with the Interconnected ~~Facility owner of~~Element the changes in ~~fault~~Fault currents.
R3	Operations Planning	Medium				The responsible entity failed to provide information to the ~~owners~~owner(s) of the ~~interconnected Facilities~~Facility associated with the Interconnected Element

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.	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 ~~agreement with~~acceptance of 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~~acceptance of 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	The responsible entity confirmed ~~agreement with~~acceptance of 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	The responsible entity confirmed ~~agreement with~~acceptance of the summary results of the Protection System 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
			~~OR~~ ~~The responsible responded to the confirmation request per R4, Part 4.3, but was late by 10 calendar days or less.~~	calendar days. ~~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.~~	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.~~	OR The responsible entity failed to confirm ~~agreement with~~acceptance of 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 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~~Element to verify coordination of existing Protection Systems where no recent study exists or when Facility configuration or ~~fault~~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~~drafting team 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~~drafting team believes applicable entities should have a documented Protection System Study for each ~~interconnected Facility~~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 ~~SDT~~drafting team believes that ~~36~~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 ~~SDT~~drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnected

~~Facilities~~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.

~~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~~Fault current, the notified entities must perform a new Protection System Study of the Interconnected ~~Facility~~Element or document why a study is not required. The ~~SDT~~drafting team recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater deviation in ~~fault~~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~~"…or technically justify why such a study is not required~~"~~." The ~~SDT~~drafting team believes the ~~6~~six-month time frame associated with this requirement represents ~~is~~ a reasonable period to perform the studies that are required after identification by the 24-month ~~fault~~Fault current review.
2. After proposing or being notified of a change at ~~an~~a Facility associated with the Interconnected ~~Facility~~Element, entities must perform a new Protection System Study, or ~~document~~technically justify why such a study is not required. The ~~SDT~~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 be performed; therefore this part of the requirement includes the statement, ~~"unless the entity can demonstrate that~~"…or technically justify why such a study is not required~~"~~." The ~~SDT~~drafting team 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~~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 ~~requires~~directs 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.~~Interconnected Element owner(s). As guidance, the ~~SDT~~drafting team 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.~~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 ~~Interconnected~~ 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 ~~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~~drafting team investigated various inputs that would trigger a review of the existing Protection System Studies~~,~~ and determined, through the experience of the ~~SDT~~drafting team members, along with informal surveys of several regional protection and control committees, that variations in ~~fault~~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~~Fault currents and includes the calculation of the percent deviation between the ~~fault~~Fault current values used in the most recent Protection System Study and the present ~~fault~~Fault current values indicated by the short~~-~~ circuit study performed pursuant to this requirement. This calculation is necessary to identify ~~fault~~Fault current changes that must be communicated in accordance with Requirement R2, Part 2.3.

Polling of ~~SDT~~drafting team membership and various protection engineering committees indicates that short~~-~~ circuit databases are customarily updated annually. Based on this information, the ~~SDT~~drafting team believes that requiring a 24-month periodic review of ~~fault~~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~~drafting team 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~~ each owner of the Facility ~~owners~~associated with the Interconnected Element when short~~-~~ circuit studies indicate that 10% deviations in ~~fault~~Fault current have occurred at the ~~Interconnected Facility.~~interconnecting bus(s). The ~~SDT~~drafting team believes the 30-day time frame associated with this requirement is reasonable for ~~sending notification~~providing the Fault current information to the interconnected entity(s) and is consistent with other NERC ~~Reliability Standards~~reliability standards.

In Requirement R2, the Transmission Owner is identified as the ~~functional entity~~Functional Entity responsible for performing the ~~fault~~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~~directs the registered functional entity initiating ~~the changes~~any change to provide the details to the other affected entities of the Interconnected ~~Facility.~~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 ~~SDT~~drafting team recognizes that ~~other~~ Facility changes ~~not directly associated with the interconnection~~at other locations can impact the Protection System Study of the Facility associated with the Interconnected ~~Facilities~~Element; e.g., the addition of a large autotransformer bank or generator not directly associated with the Interconnected ~~Facilities.~~Element. The ~~SDT~~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 ~~SDT~~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 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~~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~~: (1)~~ changes are made to Protection ~~System errors are found~~Systems during ~~misoperation~~Misoperation investigations, commissioning, ~~or~~ maintenance activities~~; (2)~~, or 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~~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 ~~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.

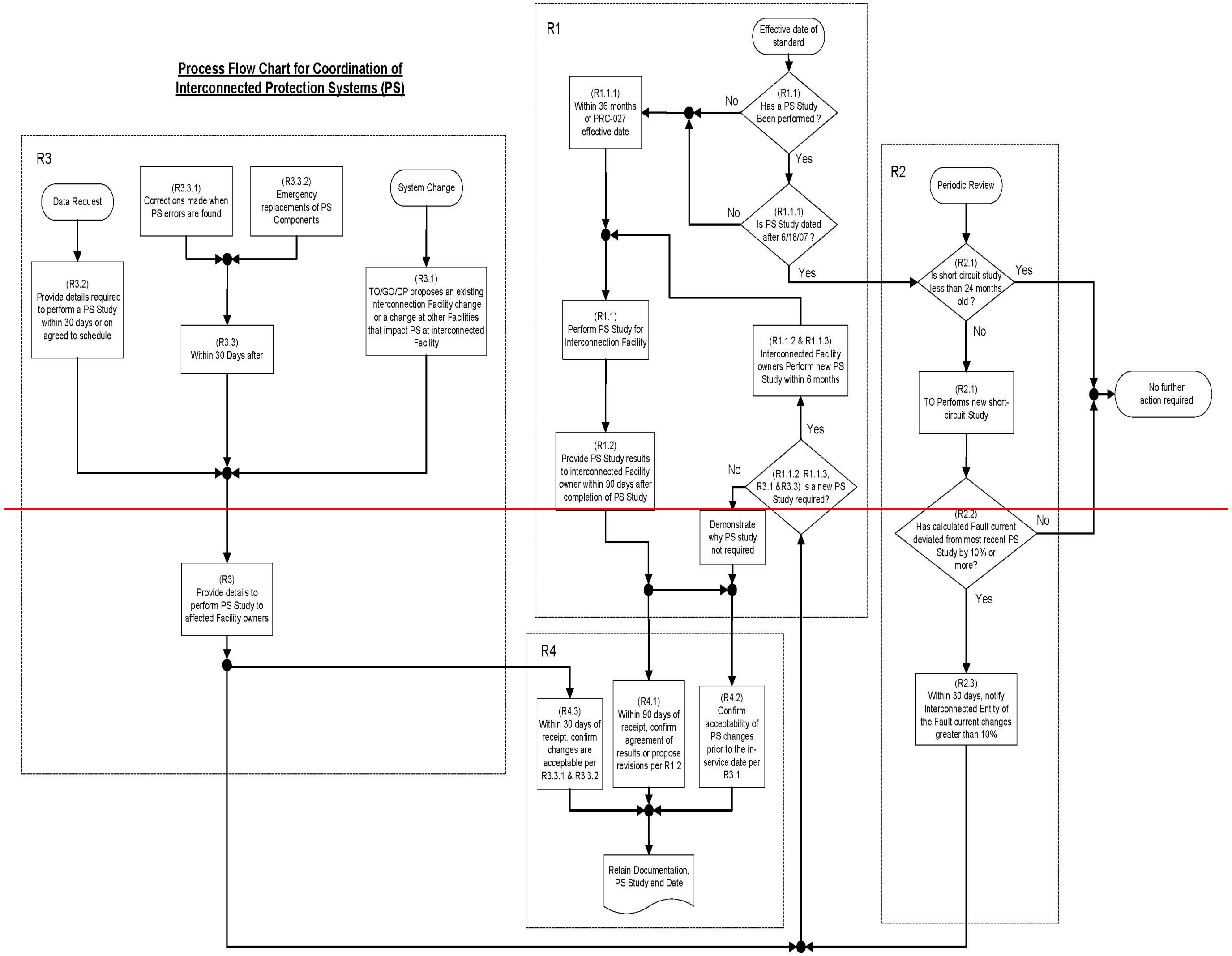
Requirement R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to ~~confirm agreement with~~review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2~~,~~; or absent ~~such agreement,~~acceptance propose revisions to achieve acceptable results. The ~~SDT~~drafting team 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~~confirm acceptance that their Protection Systems are coordinated.

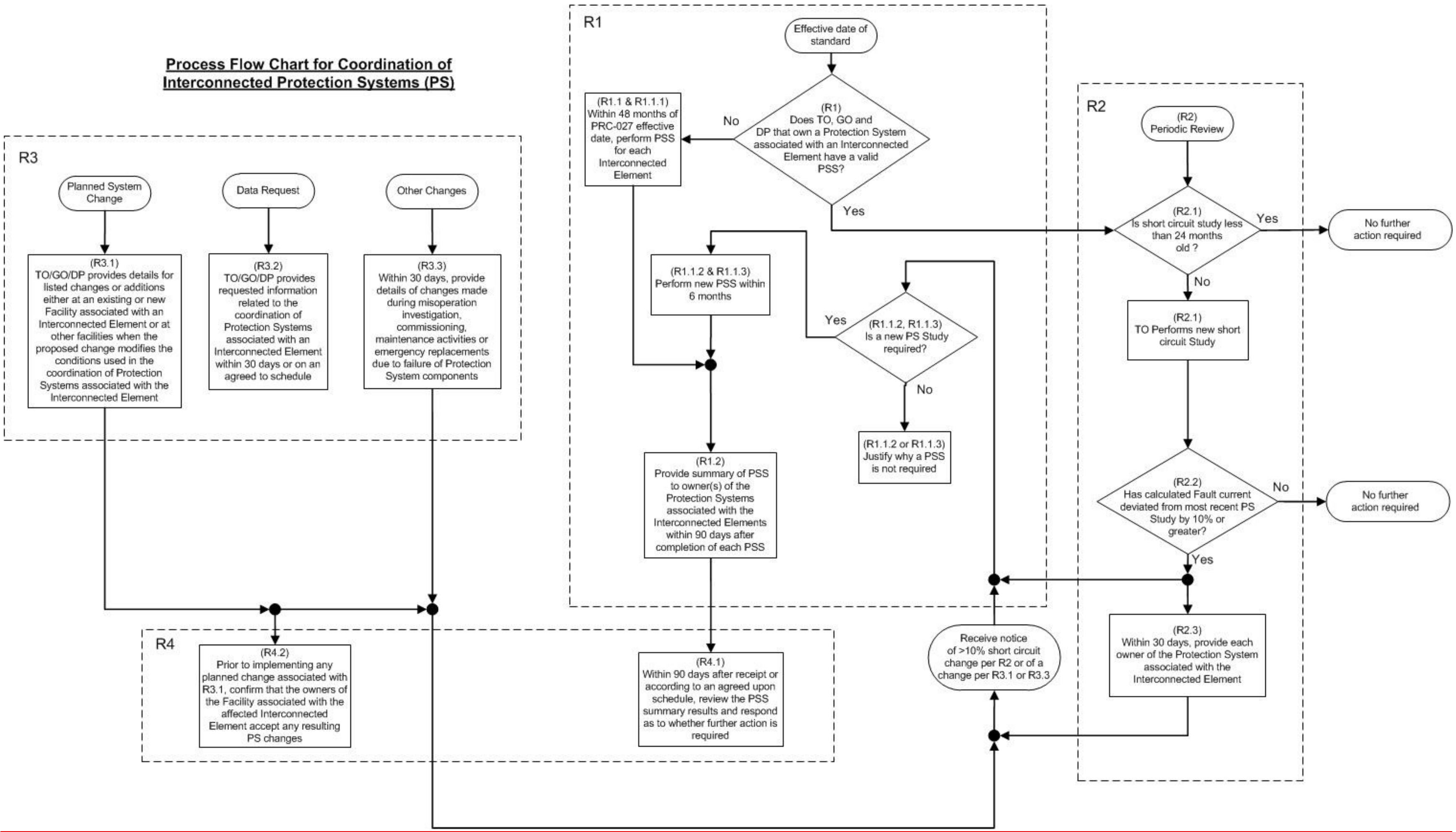
Requirement R4, Part 4.2 directs entities to confirm that planned changes described in Requirement 3.1 are acceptable prior to the in-service date of those changes. The purpose of this requirement is to assure the effects that planned changes have on Protection Systems at a Facility associated with the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


Process Flow Chart for Coordination of Interconnected Protection Systems (PS)
R3
Data Request
(R3.3.1) Corrections made when PS errors are found
(R3.3.2) Emergency replacements of PS Components
System Change
(R3.2) Provide details required to perform a PS Study within 30 days or on agreed to schedule
(R3.3) Within 30 Days after
(R3.1) TO/GO/DP proposes an existing interconnection Facility change or a change at other Facilities that impact PS at interconnected Facility
(R3) Provide details to perform PS Study to affected Facility owners
R1
Effective date of standard
(R1.1) Has a PS Study Been performed ?
No
Yes
(R1.1.1) Within 36 months of PRC-027 effective date
(R1.1.1) Is PS Study dated after 6/18/07 ?
No
Yes
(R1.1) Perform PS Study for Interconnection Facility
(R1.1.2 & R1.1.3) Interconnected Facility owners Perform new PS Study within 6 months
Yes
(R1.2) Provide PS Study results to interconnected Facility owner within 90 days after completion of PS Study
No
(R1.1.2, R1.1.3, R3.1 &R3.3) Is a new PS Study required?
Demonstrate why PS study not required
R4
(R4.3) Within 30 days of receipt, confirm changes are acceptable per R3.3.1 & R3.3.2
(R4.1) Within 90 days of receipt, confirm agreement of results or propose revisions per R1.2
(R4.2) Confirm acceptability of PS changes prior to the in-service date per R3.1
Retain Documentation, PS Study and Date
R2
Periodic Review
(R2.1) Is short circuit study less than 24 months old ?
Yes
No
No further action required
(R2.1) TO Performs new short-circuit Study
(R2.2) Has calculated Fault current deviated from most recent PS Study by 10% or more?
No
Yes
(R2.3) Within 30 days, notify Interconnected Entity of the Fault current changes greater than 10%


Process Flow Chart for Coordination of Interconnected Protection Systems (PS)
R1
Effective date of standard
(R1) Does TO, GO and DP that own a Protection System associated with an Interconnected Element have a valid PSS?
No
(R1.1 & R1.1.1) Within 48 months of PRC-027 effective date, perform PSS for each Interconnected Element
Yes
(R1.1.2 & R1.1.3) Perform new PSS within 6 months
Yes
(R1.1.2, R1.1.3) Is a new PS Study required?
No
(R1.1.2 or R1.1.3) Justify why a PSS is not required
(R1.2) Provide summary of PSS to owner(s) of the Protection Systems associated with the Interconnected Elements within 90 days after completion of each PSS
R2
(R2) Periodic Review
(R2.1) Is short circuit study less than 24 months old ?
Yes
No further action required
No
(R2.1) TO Performs new short circuit Study
(R2.2) Has calculated Fault current deviated from most recent PS Study by 10% or greater?
No
No further action required
Yes
(R2.3) Within 30 days, provide each owner of the Protection System associated with the Interconnected Element
Receive notice of >10% short circuit change per R2 or of a change per R3.1 or R3.3
R3
Planned System Change
Data Request
Other Changes
(R3.1) TO/GO/DP provides details for listed changes or additions either at an existing or new Facility associated with an 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
(R3.2) TO/GO/DP provides requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 days or on an agreed to schedule
(R3.3) Within 30 days, provide details of changes made during misoperation investigation, commissioning, maintenance activities or emergency replacements due to failure of Protection System components
R4
(R4.2) Prior to implementing any planned change associated with R3.1, confirm that the owners of the Facility associated with the affected Interconnected Element accept any resulting PS changes
(R4.1) Within 90 days after receipt or according to an agreed upon schedule, review the PSS summary results and respond as to whether further action is required

Example Process

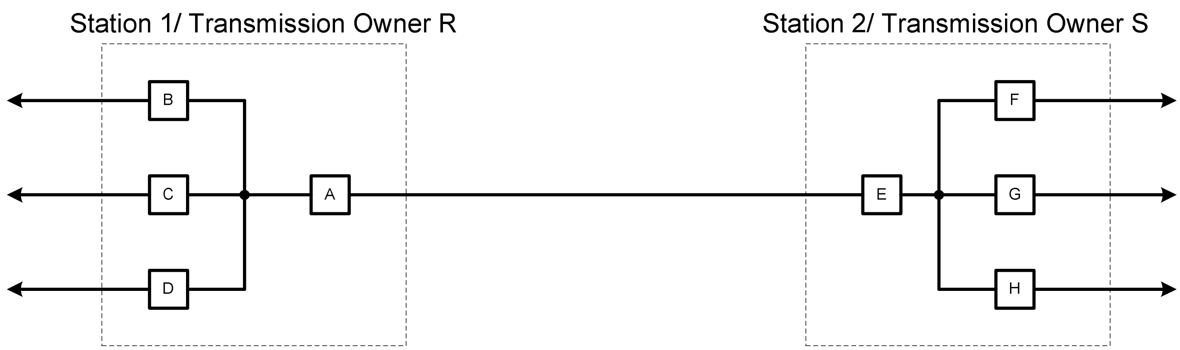
An example of the interaction between entities required to gather the information to perform an accurate study is below.

- 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~~standard between owners of Facilities associated with the affected Interconnected ~~Facilities.~~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.

Figure 1



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

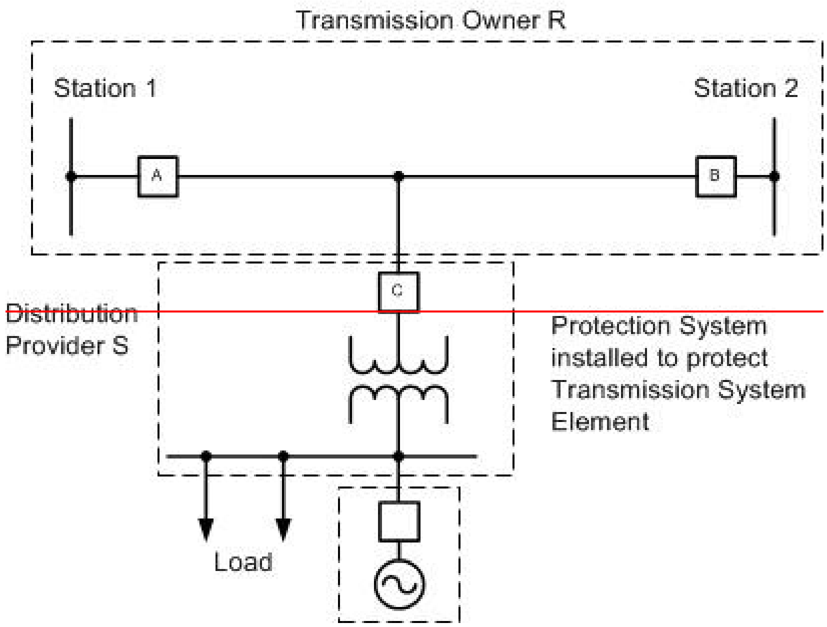
Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 1, ~~the responsibility for~~ Owner S is to ~~verify that~~review the Protection System settings associated with Breaker A (provided by Owner R) ~~do not result in~~for coordination issues with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

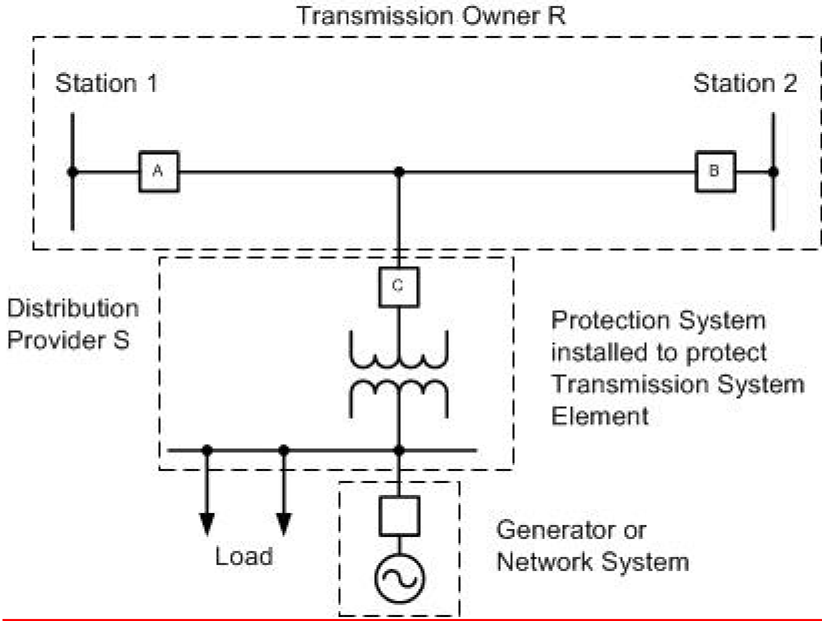
Figure 2

In Figure 2 above, the ~~interconnecting~~ Interconnected Element between the Transmission ~~to Generation Interconnected Facilities (Station 1 – Generation~~ Owner ~~R~~ and ~~Station 2 – Transmission~~the Generator 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~~review the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems ~~do not result in~~for 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~~review the Protection System settings associated with Breaker C (provided by Owner S) ~~do not result in~~for coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3





In Figure 3 above, the ~~interconnecting~~ Interconnected Element between the Transmission Owner ~~to~~and the 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~~review the Protection System settings associated with Line Breaker C (provided by Distribution Provider S) ~~and the generator Protection Systems do not result in~~for 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~~

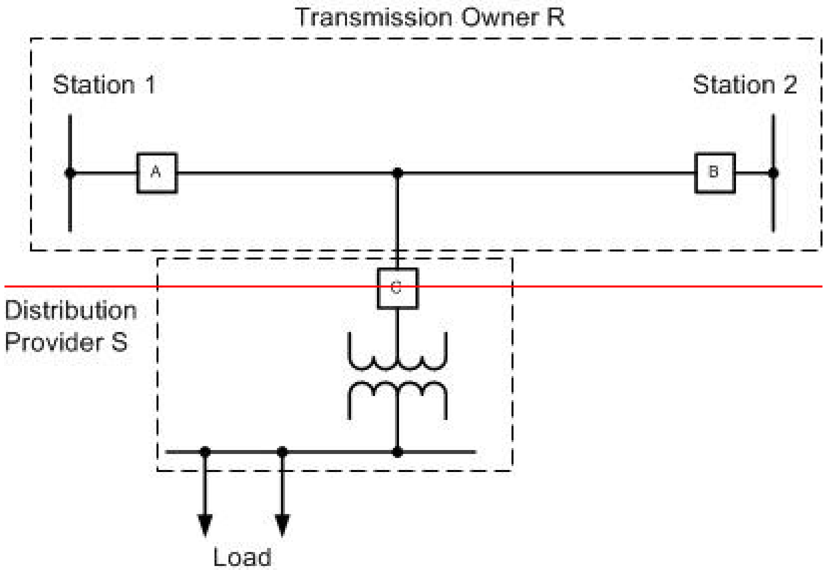
~~settings associated with Breakers A and B (provided by Owner R) do not result in coordination issues with the Protection System settings associated with Breaker C and the generator Protection Systems. In order to perform this verification, it will be necessary that the Generator Owner provide Distribution Provider S with its generator Protection System settings.~~

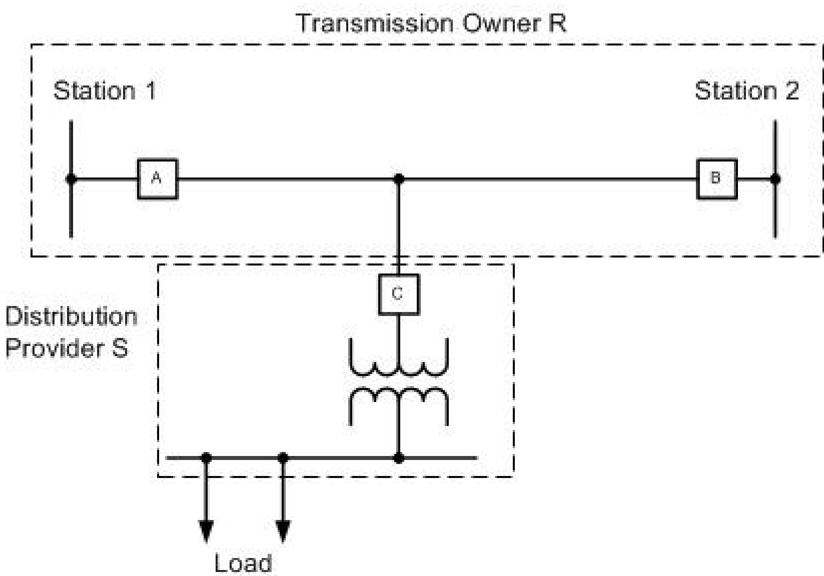
~~Note:~~ Notes:

A Protection System Study is required per this ~~Standard~~standard for this example if a Protection System at the Distribution Provider's substation is designed to ~~protect BES transmission system Elements~~detect Faults on the BES Transmission System.

"Protection Systems installed 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 to detect faults on the BES Transmission System."

Figure 4



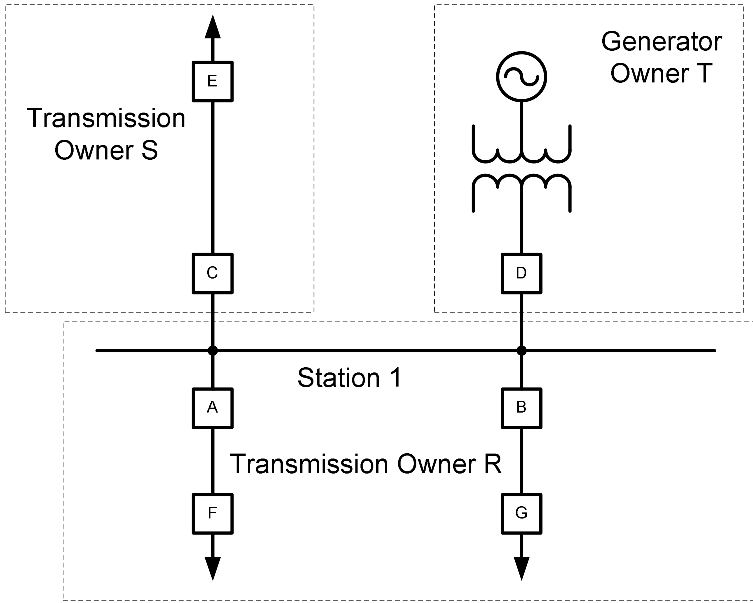


In Figure 4 above, the ~~interconnecting~~ Interconnected Element between the Transmission Owner ~~to~~and the Distribution Provider ~~Interconnected Facilities (Transmission Owner R line between Breakers A and B – Distribution Provider S)~~ is the transmission line or tap between the line and Breaker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

Note: No specific Protection System Study is required per this ~~Standard~~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~~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 associated with the Facilities in Figure 5:

~~The responsibility for~~ Owner R is to ~~verify that~~review 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~~for coordination issues with the Protection System settings associated with Breakers A, B.

~~The responsibility for~~ Owner S is to ~~verify that~~review 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~~for coordination issues with the Protection System settings associated with Breaker C. To perform this ~~verification~~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.

~~The responsibility for~~ Owner T is to ~~verify that~~review the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R or S) ~~do not result in~~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 ~~verification~~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.

Standard Development Roadmap

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

Development Steps Completed:

1. 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. PRC-001-2 was approved by the NERC Board of Trustees on May 9, 2012. The legacy Requirements R2, R5, and R6 of
~~4.~~ PRC-001-1 were retired.~~Transitioned from a revision 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.~~

Note: The Project 2007-03 Real-time Operations SDT recently proposed revisions to PRC-001-1. A redlined version of PRC-001-1 was posted with the three operating time frames (Requirements R2, R5, and R6) deleted. The resulting clean version of PRC-001-2, containing the remaining three legacy Requirements R1, R3, and R4 of PRC-001-1, was also posted. The Project 2007-06 System Protection Coordination SDT is recommending retirement of the legacy Requirements R3 and R4 of PRC-001-1 that remain in PRC-001-2 (now R2 and R3) because those requirements address Protection System coordination issues included in PRC-027-1. This redlined version shows the changes proposed to PRC-001-2. A mapping document is also posted showing the disposition of those legacy requirements of PRC-001-1 to the proposed requirements of PRC-027-1. The ballot of PRC-001-3 is associated with the approval of PRC-027-1 and the implementation plan for this project.

Proposed Action Plan and Description of Current Draft:

The Project 2007-06 System Protection Coordination SDT is recommending retirement of the legacy Requirements R2 and R3 of PRC-001-2 because those requirements address Protection System coordination issues included in the new Reliability Standard PRC-027-1. This redlined version of PRC-001-2 shows the proposed changes. The SPC SDT is posting PRC-001-3 and PRC-027-1 for stakeholder comments under a 45-day formal comment period. The ballot of PRC-001-3 is associated with the approval of PRC-027-1 and the implementation plan for this project.

~~The 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. The SPC SDT is requesting a posting for stakeholder comments under a 30-day formal comment period.~~

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	3Q12

2. Post for recirculation ballot.	1Q13
3. Submit to BOT.	1Q13

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.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title: System Protection Coordination**
2. **Number:** PRC-001-~~2~~3
3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where ~~no~~ regulatory approval is not required, the ~~requirements~~ standard shall become effective on the first day of the first calendar ~~quarter~~ quarter that is twelve months ~~following~~ 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. ~~adoption.~~

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. *[Violation Risk factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~**R2.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.~~

~~**R2.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*~~

~~**R2.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*~~

~~**R3.** Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*~~

C. Measures

~~**M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence~~

~~that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 2, 2.1, and 2.2.~~

D. Compliance

Updated to add latest default language.

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

~~1.2. Compliance Monitoring and Reset Time Frame~~

~~One or more of the following methods will be used to assess compliance:~~

- ~~Self-certification (Conducted annually with submission according to schedule.)~~
- ~~Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)~~
- ~~Periodic Audit (Conducted once every three years according to schedule.)~~
- ~~Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period, and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

~~1.3.~~1.2. Data 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.

Updated to add a ~~latest default language~~time retention period for the

~~Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.~~

Each responsible entity shall keep evidence to demonstrate compliance with Requirement R1 for the previous three calendar years.

If an entity is found non-compliant, the entity shall keep information related to the noncompliance until mitigation is complete and approved~~until found compliant,~~ or for ~~two years plus the current year~~the time period specified above, whichever is longer.

~~Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,~~

The Compliance ~~Monitor~~ Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

~~1.4.~~1.3. Compliance Monitoring and Assessment Processes

One or more of the following methods will be used to assess compliance:

- Compliance Audit
- Self-certification
- ~~(Conducted annually with submission according to schedule.)~~
- Spot Checking ~~Audits (Conducted anytime with up to 30 days notice given to prepare.)~~
- Compliance Investigation
- Self-Reporting
- Complaint
- ~~Periodic Audit (Conducted once every three years according to schedule.)~~
- ~~Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period, and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~1.5.~~1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement #	VRF	Time Horizon	Lower	Moderate	High	Severe
R1	High	Operations Planning, Same-day Operations, Real-time Operations	N/A	N/A	The responsible entity failed to be familiar with the limitations of protection system schemes applied in its area.	The responsible entity failed to be familiar with the purpose of protection system schemes applied in its area.
~~**R2**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~N/A~~	~~N/A~~	~~N/A~~
~~**R2.1**~~	~~High~~	~~Operations Planning, Same-day Operations, Real-time Operations~~	~~The Generator Operator failed to coordinate one new protective system or protective system change with either its Transmission Operator or its Host Balancing Authority or both.~~	~~The Generator Operator failed to coordinate two new protective systems or protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.~~	~~The Generator Operator failed to coordinate three new protective systems or protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.~~	~~The Generator Operator failed to coordinate more than three new protective systems or protective system changes with its Transmission Operator or its Host Balancing Authority, or both.~~
~~**R2.2**~~	~~High~~	~~Operations Planning, Same-day Operations, Real-time Operations~~	~~The Transmission Operator failed to coordinate one new protective system or protective system change with neighboring~~	~~The Transmission Operator failed to coordinate two new protective systems or protective system changes with neighboring~~	~~The Transmission Operator failed to coordinate three new protective systems or protective system changes with~~	~~The Transmission Operator failed to coordinate more than three new protective systems or protective system changes~~

			~~Transmission Operators or Balancing Authorities or both.~~	~~Transmission Operators or Balancing Authorities or both.~~	~~neighboring Transmission Operators or Balancing Authorities or both.~~	~~with neighboring Transmission Operators or Balancing Authorities or both.~~
~~R3~~	~~High~~	~~Operations Planning, Same-day Operations, Real-time Operations~~	~~The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with one of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.~~	~~The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with two of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.~~	~~The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with three of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.~~	~~The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with three or more of its neighboring Generator Operators, Transmission Operators, and Balancing Authorities.~~

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	May 9, 2012	Delete data Requirements R2, R5, and R6, as they are now addressed in TOP-003-2.	Revised
3	TBD	Delete Requirements R2 and R3, as they are now addressed in PRC-027-1.	Revised

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Implementation Plan

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

Approvals Requested

- PRC-027-1 Protection System Coordination for Performance During Faults
- PRC-001-3 System Protection Coordination

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Protection System Coordination for Performance During Faults	X	X	X			
PRC-001-3: System Protection Coordination				X	X	X

Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definitions 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 ~~Facilities~~Element: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity~~BES Facilities that are electrically joined by one or more Element(s) and are owned by different 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.

Background

On December 7, 2006, the NERC Planning Committee approved the assessment of Standard PRC-001-1 (System Protection Coordination) prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF asserted:

> *"The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In*

addressing the 'operating horizon, operations planning horizon, and planning horizon' protection coordination issues, the deficiencies in the current standard are magnified."

And further:

"The SPCTF… recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards."

The Standard Committee approved the Standard Authorization Request with modifications 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.

With the development of the proposed Reliability Standard PRC-027-1, the Standard Drafting Team (SDT) for Project 2007-06 – System Protection Coordination, has followed the observations and recommendation of the NERC SPCTF assessment of PRC-001-1 which had six requirements. The SDT accomplishes this by:

1. Incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) and moving those requirements into a new standard (as recommended by the SPCTF assessment), focusing on the performance of Protection Systems during Faults.
2. Assigning responsibility for coordination of Protection Systems during Faults to the appropriate functional entities – the Protection System equipment owners, specifically: Transmission Owners, Generator Owners, and Distribution Providers.
3. Transferring the responsibility of addressing the three operating horizon Requirements R2, R5, and R6 of PRC-001-1 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standard(s) within that project. (The NERC Board of Trustees approved these changes proposed by the Project 2007-03 team when it approved PRC-001-2 on May 9, 2012.)
4. Leaving the legacy Requirement R1 of PRC-001-2 in PRC-001-3 (thereby not creating a reliability gap) until it is incorporated into a new or revised reliability standard.

Effective Date of New or Revised Standards and Definitions

PRC-027-1 - Protection System Coordination for Performance During Faults

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. ~~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~~ 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.

PRC-001-3 – System Protection Coordination
Same effective date as PRC-027-1.

Effective Date for Definitions

The two proposed definitions (Interconnected Facilities and Protection System Study) shall become effective at the same time as PRC-027-1.

Retirement:

PRC-001-2 – Protection System Coordination shall be retired at midnight the day before PRC-001-3 becomes effective.

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Project 2007-06 System Protection Coordination Mapping Document

Mapping Document Showing Translation of PRC-001-2 – System Protection Coordination to PRC-027-1 – Protection System Coordination for Performance During Faults
Updated 10-31 to reflect changes made to requirements

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	Retained	NA
R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R2.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.	PRC-027-1, R1, R3, & R4 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Study for each Interconnected Element on its System, to coordinate Protection Systems, such that the least number of power system Elements are isolated to clear Faults as follows: **1.1.3.** 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.

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R2.2 Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.		**1.2.** 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, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each Protection System Study. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Responsible Entity connected to the same Interconnected Element: **3.1.** Details (e.g., project schedule, protective relaying scheme types and settings) 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

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		• 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**.** **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **4.2.** 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.
R3. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with	PRC-027-1, R1, R2, R3, &	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Study for each Interconnected Element

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	R4 Note: Applicability changed to GO, TO and DP	on its System, to coordinate Protection Systems, such that the least number of power system Elements are isolated to clear Faults as follows: **1.1.1.** Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists. **1.1.2.** Within 6 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. **1.2.** 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, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each Protection System Study. **R2.** For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall: **2.1.** 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

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		System Study is available per Requirement R1. **2.2.** Calculate the percent deviation 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 and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation: $$\% \, Deviation = \left(\frac{Iscs - Ipss}{Ipss}\right) x \; 100$$ Where: I_{scs} = Fault current value from present short-circuit study And: I_{pss} = Fault current value used in the most recent Protection System Study **2.3.** Where the calculation performed, pursuant to Requirement R2, Part 2.2, 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), within 30 calendar days after identification. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Responsible Entity connected to the same Interconnected Element: **3.2.** Requested information related to the coordination of Protection

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		Systems associated with an Interconnected Element within 30 calendar days of receiving a request or according to an agreed-upon schedule. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **4.1.** 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.

Unofficial Comment Form for 2nd Draft of PRC-027-1: Protection System Coordination for Performance During Faults

Project 2007-06

Please **DO NOT** use this form to submit comments on the 2nd draft of the standard for Protection System Coordination for Performance During Faults. Comments must be submitted by **[Due Date in bold]**. If you have questions please contact Al McMeekin at al.mcmeekin@nerc.net or by telephone at 803-530-1963.

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

Background Information:

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPCSDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPCSDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions; consequently, the SPCSDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. Additionally, the SPCSDT determined that the training aspects of PRC-001-1 Requirement R1 are more appropriately addressed by Reliability Standard PER-005-1 with revision to its Applicability section to include the Generator Operator. The two remaining requirements, Requirements R3 and R4 of PRC-001-1 address the coordination of new and existing protective systems. These aspects of coordination are incorporated in the proposed standard PRC-027-1 Protection System Coordination for Performance During Faults.

Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012. The SPCSDT has responded to stakeholder comments and incorporated pertinent suggestions into the standard. The SPCSDT is presenting the second draft of PRC-027-1 for stakeholder review and comment.

For questions 1-6, please provide specific comments related to the individual question.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

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.

   ☐ Yes

   ☐ No

   Comments:

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.

   ☐ Yes

   ☐ No

   Comments:

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.

   ☐ Yes

   ☐ No

   Comments:

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.

   ☐ Yes

   ☐ No

   Comments:

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.

   ☐ Yes

   ☐ No

   Comments:

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 mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received and Other changes in the standard:

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 phase '…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards', and (2) the inclusion of the phrase '… remove

[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 drafting team modified Requirement R1, Part 1.1 to be consistent with the Purpose to read as follows: "Perform a Protection System Study for each Interconnected Element on its System, to coordinate Protection Systems, such that the least number of power system Elements are isolated to clear Faults as follows:"

The timeframe 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 6 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: "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: "Provide to each affected Interconnected Element owner 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 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 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 2.2 was modified to replace "V" with "I".

The drafting team modified Requirement R2, Part 2.3 to provide clarity and to change "notify" to "provide" such that it now reads: "Where the calculation performed, pursuant to Requirement R2, Part 2.2, 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), within 30 calendar days after identification."

The drafting team modified Requirement R3 for clarity and moved the examples into Requirement 3, Part 3.1 such that it now reads: "Each Transmission Owner, Generator Owner, and Distribution Provider shall provide 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 (e.g., project schedule, protective relaying scheme types and settings) 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 the 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 & 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 increments for tardiness were lengthened from 10 days to 30 days.
- Editorial changes were made to the VSLs for Requirement R2, Part 2.3; the phrase "as described in R2, Part 2.3" was added.
- Editorial changes were made to the VSLs for Requirement R4, Part 4.3; the word "entity" was added.

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 timeframe in Parts 3.2 and 3.3 while other commenters wanted them eliminated. The drafting team explained that they believed the 30-day timeframe 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, 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 timeframes associated with the coordination process and the burden of documentation. The drafting team believes the assigned timeframes 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

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. .... 18~~13~~
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.43~~33~~

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.................. 59~~44~~

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. .... 87~~63~~

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.. 114~~82~~

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.143~~101~~

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. .... 163~~115~~

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.......................... 180~~127~~

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.)192~~136~~

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	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
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

Group/Individual		Commenter	Organization	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

Group/Individual		Commenter	Organization	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	

NERC

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

Group/Individual		Commenter	Organization	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

Group/Individual		Commenter	Organization	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	

Group/Individual		Commenter	Organization	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

Group/Individual		Commenter	Organization	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

Group/Individual		Commenter	Organization	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 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</u>

Organization	Yes or No	Question 1 Comment
		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 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."**		
Southwest Power Pool NERC	No	We would ask that the team revise the second part of the purpose to lead in