Meeting Notes

Project 2007-06 System Protection Coordination Standard Drafting Team

August 13-16, 2013

Tri-State Generation and Transmission Association, Inc.
Westminster, CO

Administrative

1. **Introductions**

   The meeting was brought to order by Chair, Phil Winston at 8:00 a.m. MT on Tuesday, August 13, 2013. Building and safety information/logistics were provided by Bill Middaugh of Trr-State. 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	
Kevin Thompson	ITC Holdings	Observer	X	
Juan Villar	FERC	Observer	X	
Forrest Brock	Western Farmers Electric Cooperative	Member	X	
Jeffrey Iler	American Electric Power	Member	X	
Al McMeekin	NERC Staff	Member	X	

2. **Determination of Quorum**

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

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

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

4. **Review team roster**

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

Agenda

1. **Discuss developments since last meeting**

   Mr. Winston discussed the July 2013 ballot results informing the team that we had made significant progress. Draft 3 of PRC-027-1 garnered 52.71 % in the weighted segment approval process – an increase of 19 %. A brief review of the comments revealed that approximately 70% of stakeholders agreed with the drafting team's direction.

   Mr. Winston had made the following assignments via email:

   - Provide draft response to comments by noon ET Monday July 15, 2013.

     Note: Included in this should be any suggested changes to the Standard that you are proposing. This should be summarized in the Summary of comment section for your assigned question.

   - Mr.McMeekin will provide the completed draft back to the team by noon ET July 22, 2013.
   - Mr.McMeekin will send out a poll for potential meeting date(s) starting the week of July 22, 2013 and beyond.

   1. Based on stakeholder comments, the drafting team modified the Purpose of this standard to:

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

   Do you agree with this Purpose? If not, please provide specific suggestions for improvement in the comment area.

   Sam Francis

   2. The drafting team modified the proposed definition of **Interconnected Element** to read as follows:

   Interconnected Element: A BES Element that electrically joins facilities owned by:

   a. separate Registered Entities, or

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

Do you agree with the revised definition? If not please provide specific suggestions for improvement in the comment area.

David Cirka

3. In Requirement R1, the drafting team modified the time frame to allow entities 60 months to have a documented Protection System Coordination Study (PSCS) completed for each Interconnected Element if no PSCS exists. Note, the drafting team has allowed inclusion of all previously performed PSCS whose summary of results include, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed.

Do you agree with this revised time frame? If not, please provide specific suggestions for change in the comment area.

Jeff Iler

4. In Requirement R2, the drafting team modified the time frame to 60 months for either conducting a Fault current review or provide a technical justification as to why a Fault current review is not necessary.

Do you agree with this revision to Requirement R2? If not, please provide specific suggestions for improvement in the comment area.

Kevin Wempe

5. In Requirement R4, the drafting team has clarified the expectation of what a response to a review of the summary results of a Protection System Coordination Study should include. The options are as follows:

a. Accepting the results, or

b. Rejecting the results and suggesting modifications to resolve any identified coordination issues.

Do you agree with this revision to Requirement R4? If not, please provide specific suggestions for improvement in the comment area.

Phil Waudby

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

Phil Winston

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

Phil Winston

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

Bill Middaugh – 1st half
Forest Brock – 2nd half

2. **Develop responses to comments**

   The SDT made excellent progress completing the responses to Questions 1 – 5. Questions 6 and 7 regarding PRC-001 were answered by providing the summary response developed by NERC staff. Question 8 responses previously developed will be reviewed/revised based on the team responses developed this week.

3. **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 drafting team disagreed on the technical justification aspect of Requirement R2, specifically whether an entity should be permitted to technically justify why Fault current does not affect the Protection System coordination instead of performing a short circuit study once every 60 calendar months. Some team members believe there is a reliability benefit in notifying the other owners of a 10% change in Fault current at the interconnecting bus. A motion was made by Jeff Iler of AEP and seconded by Forrest Brock of Western Farmers Electric Cooperative to remove the phrase "technically justify why a change in total bus Fault current does not affect the Protection System coordination." An email ballot was conducted and the drafting team voted 7-1 to remove the language from Requirement R2. The results are attached.

4. **Next steps**

   The SDT will review the developed comments in preparation for our next meeting.

5. **Future meeting(s)**

   ONCOR Headquarters, Ft. Worth, TX – August 27-29, 2013.

6. **Adjourn**

The SDT thanked Tri-State for its hospitality and the Chair adjourned the meeting at 11:00 a.m. MT on Friday, August 16, 2013.

Standard Development Timeline

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

Development Steps Completed

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

Description of Current Draft

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

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

Effective Dates:

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

Version History

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

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here.

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

~~Interconnected~~ Interconnecting Element: A BES Element that electrically joins ~~f~~Facilities ~~owned by~~:
a) owned by separate Registered Entities, or
b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

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

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

A. Introduction

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

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

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

~~4.2.~~ 4.2

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

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

5. **Background:**

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

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

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address all issues identified by the SPCTF assessment of PRC-001-1. The SPC SDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focused their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and clarified in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

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

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

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

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

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

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

- Underfrequency Load shedding programs are addressed in PRC-006-1. Generator performance during frequency excursions is being addressed in PRC-024-1 by Project 2007-09 Generator Verification.

- Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed in PRC-024-1 by Project 2007-09, Generator Verification.

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

- Transmission relay loadability is addressed in PRC-023-2.

- Generator relay loadability will be addressed in PRC-025-1 by ~~Phase 2 of Relay Loadability: Generation, in~~ Project 2010-13.2, Phase 2 of Relay Loadability: Generation.

- Protective relay response during power swings will be addressed by ~~Phase 3 of~~ Project 2010-13.3, Phase 3 of Relay Loadability: Stable Power Swings.

- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and will be improved in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

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

B. Requirements and Measures

Rationale for R1:

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

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

Part 1.1.2 The drafting team believes that 12 calendar months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current change at an interconnecting bus, where such conditions may warrant a new PSCS, or to technically justify why no such study is required. Refer to the Application Guidelines for Requirement R2 for examples of ~~p~~Protection ~~s~~Systems where technical justifications may be used.~~, e.g., when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current.~~

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

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

Note: In cases where a single group performs an overall coordination study for a given ~~Interconnected~~Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by ~~both Registered~~all ~~e~~Entities.

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

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

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

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

1.1.3 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1.

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

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

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, and 1.1.3 is a dated PSCS, or the summary results of each PSCS (hard copy or electronic file formats) demonstrating the time frames specified or agreed to in Parts 1.1.1, 1.1.2, and 1.1.3 were achieved. Acceptable evidence of a technical justification for not performing a PSCS as specified in Parts 1.1.2 and 1.1.~~3~~ 4 may include, but is not limited to, documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any aspect~~s~~ of coordination.

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

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

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

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

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

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

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

R2. For each ~~Interconnected~~ Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months, technically justify why a change in total bus[am2] Fault current does not affect the Protection System coordination, or: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with ~~Interconnected~~Interconnecting Elements affirm that the Protection System(s) applied are acceptable per the conditions identified in Parts 4.1 and 4.2.

Part 4.1 The drafting team believes 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with ~~Interconnected~~Interconnecting Elements to review the summary results of a PSCS and respond. Note: Per Requirement R1, Part 1.2, at a minimum, the summary results of a PSCS must include the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. The response should indicate ~~acceptance with the review~~ the results/conclusions were reviewed; or ~~rejection of or disagreement with the review results/conclusions and offer of~~ suggestions/modifications to resolve any identified coordination issues. The drafting team recognizes there could be situations where one owner may not agree with the other owner's protection philosophy but they accept the proposed changes since no coordination issues were identified.

Part 4.2 The drafting team believes that proposed changes or modifications (including project schedules) to Facilities associated with the ~~Interconnected~~Interconnecting Element, as described in Requirement R3, Part 3.1, or modifications suggested in Requirement R4, Part 4.1 must be communicated and ~~accepted~~ a response received prior to the in-service date. The review~~Acceptance~~ assures that the owners~~coordination~~ of Protection Systems associated with the affected Interconnected Element are aware of the changes and have responded with comments if necessary~~is achieved~~.

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

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

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

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with ~~Interconnected~~Interconnecting Elements affirm that the Protection System(s) applied are acceptable per the conditions identified in Parts 4.1 and 4.2.

Part 4.1 The drafting team believes 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with ~~Interconnected~~Interconnecting Elements to review the summary results of a PSCS and respond. Note: Per Requirement R1, Part 1.2, at a minimum, the summary results of a PSCS must include the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. The response should indicate ~~acceptance with the review~~ the results/conclusions were reviewed; or ~~rejection of or disagreement with the review results/conclusions and offer of~~ suggestions/modifications to resolve any identified coordination issues. The drafting team recognizes there could be situations where one owner may not agree with the other owner's protection philosophy but they accept the proposed changes since no coordination issues were identified.

Part 4.2 The drafting team believes that proposed changes or modifications (including project schedules) to Facilities associated with the ~~Interconnected~~Interconnecting Element, as described in Requirement R3, Part 3.1, or modifications suggested in Requirement R4, Part 4.1 must be communicated and ~~accepted~~ a response received prior to the in-service date. The review~~Acceptance~~ assures that the owners~~coordination~~ of Protection Systems associated with the affected Interconnected Element are aware of the changes and have responded with comments if necessary~~is achieved~~.

~~R4.~~R5. Prior ~~Each~~ to implementing any proposed change(s) or addition(s) associated with Requirement R3, Part 3.1, each Transmission Owner, Generator Owner, and Distribution Provider shall confirm there are no outstanding coordination issues associated with the affected Interconnecting Element. ~~Transmission Owner, Generator Owner, and Distribution Provider shall:~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

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

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

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

M10. Acceptable evidence for Requirement R5~~4, Part 4.2~~ is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes or ~~modifications~~additions, communications (e.g. email acknowledgements) of those changes were ~~completed~~reviewed, and any identified coordination issues were ~~resolved and accepted~~addressed.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by less than or equal	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required but was late by more than 60 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 30

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			to 10 calendar days.	equal to 20 calendar days.	equal to 30 calendar days.	calendar days. OR The responsible entity failed to perform a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, or 1.1.3. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2 or 1.1.3. OR The responsible entity failed to provide Protection System Coordination Study results in accordance with Requirement R1, Part 1.2.
R2	Long-term Planning	Medium	For an ~~Interconnected~~Interconnecting Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by less than or equal to 30	For an ~~Interconnected~~Interconnecting Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 30 calendar	For an ~~Interconnected~~Interconnecting Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 60 calendar	For an ~~Interconnected~~Interconnecting Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 90 calendar

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			calendar days. OR The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1,	days but less than or equal to 60 calendar days. OR The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1,	days but less than or equal to 90 calendar days. OR The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1,	days. OR The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault currents, according to the equation designated in Requirement R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 30

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			but was late by less than or equal to 10 calendar days.	but was late by more than 10 calendar days but less than or equal to 20 calendar days.	but was late by more than 20 calendar days but less than or equal to 30 calendar days.	calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.
R3	Operations Planning	Medium	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days. OR The responsible entity provided the information required in Requirement R3,	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the information required in Requirement R3,	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the information required in Requirement R3,	The responsible entity failed to provide the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, details for any proposed change or addition identified in Requirement R3, Part 3.1. OR The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Part 3.3, but was late by less than or equal to 10 calendar days.	Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.
R4	Operations Planning	Medium	The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.	The responsible entity responded in more than 120 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1. OR The responsible entity failed to review the summary results of the Protection System Coordination Study provided to them in accordance with Requirement R4, Part 4.1. OR The responsible entity failed to respond to the other owners in accordance with Requirement R4, Part 4.1. OR The responsible entity failed to affirm that the other

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						owner(s) of each Facility associated with the affected ~~Interconnected~~Interconnecting Element accepted the Protection System(s) changes including the resolution of any identified coordination issues, prior to implementation of those changes, as required in Requirement R4, Part 4.2.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Purpose:

To coordinate Protection Systems for ~~Interconnected~~Interconnecting Elements, such that Protection System components operate in the desired sequence during Faults.[p3]

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

Requirement R1:

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

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

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

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

PSCSs comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in PSCSs include maximum generation with the transmission system under normal operating conditions and under single contingency conditions. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), ~~and~~ adequate directional polarizing quantities, a technical justification explaining why Fault current does not impact your Protection Systems, and sensitivity to Fault current levels.

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

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

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

2. After proposing or being notified of a change at a Facility associated with the ~~Interconnected~~Interconnecting Element, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the proposed or notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the timeframe associated with performing a PSCS for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3, Part 3.1 is unnecessary because notification of such a change may occur weeks or years prior to the change

due to the wide variety of conditions that may be associated with a particular change. The drafting team sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2. The drafting team believes that six calendar months is an appropriate period of time for entities to perform the studies required, or to technically justify why no such study is needed, when details of changes are provided associated with Requirement R3 Part 3.3.

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

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

Requirement R2:

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

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

1. Differential elements

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

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

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

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

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

Requirement R3:

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

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

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

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

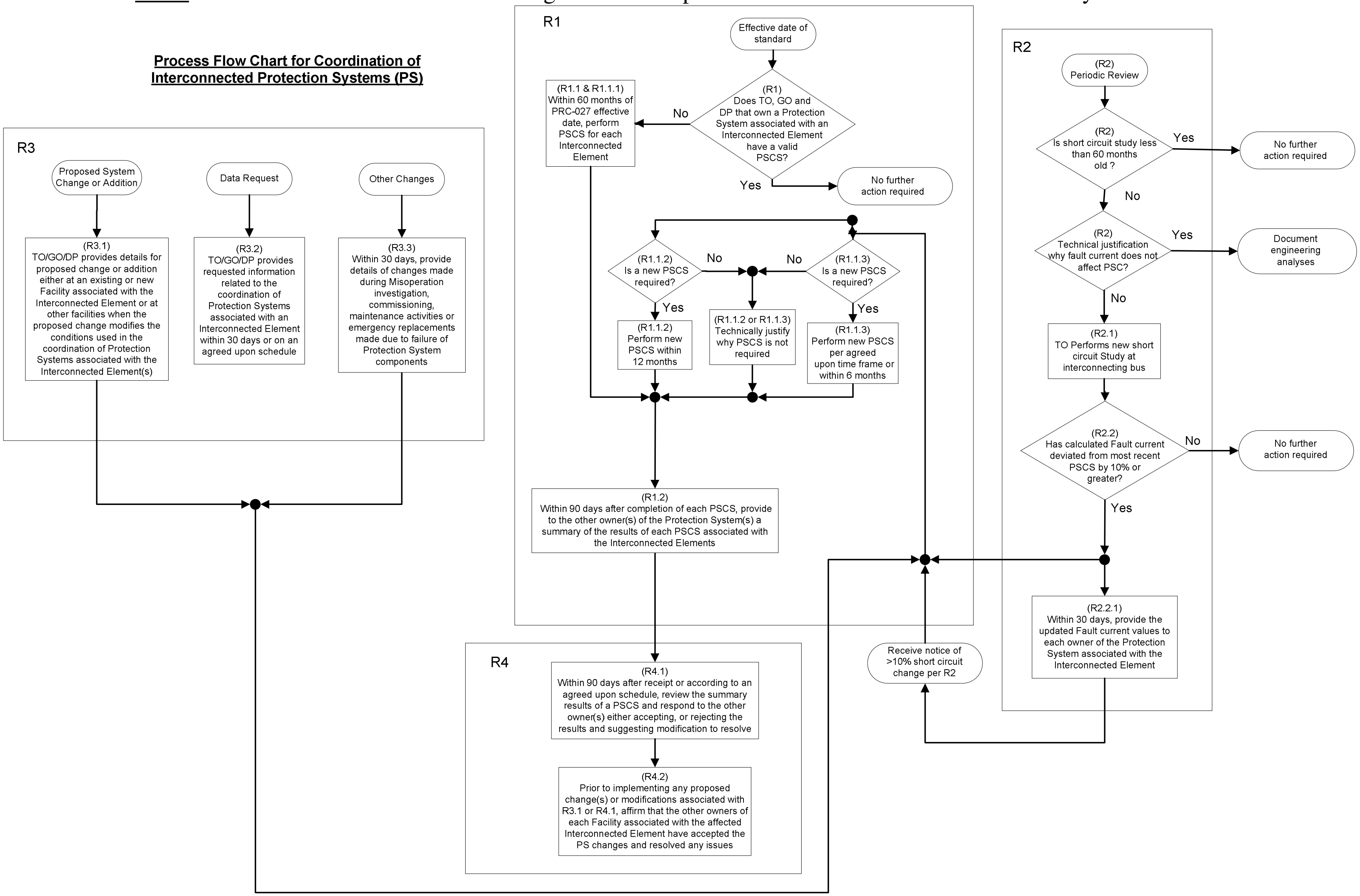
Requirement R4:

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

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

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

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



Example Process

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

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

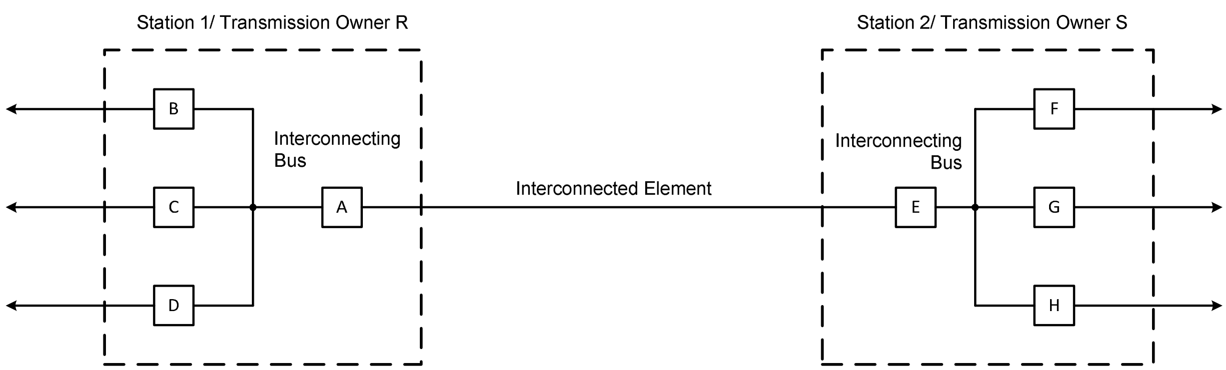
Diagrams

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

NOTES:

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

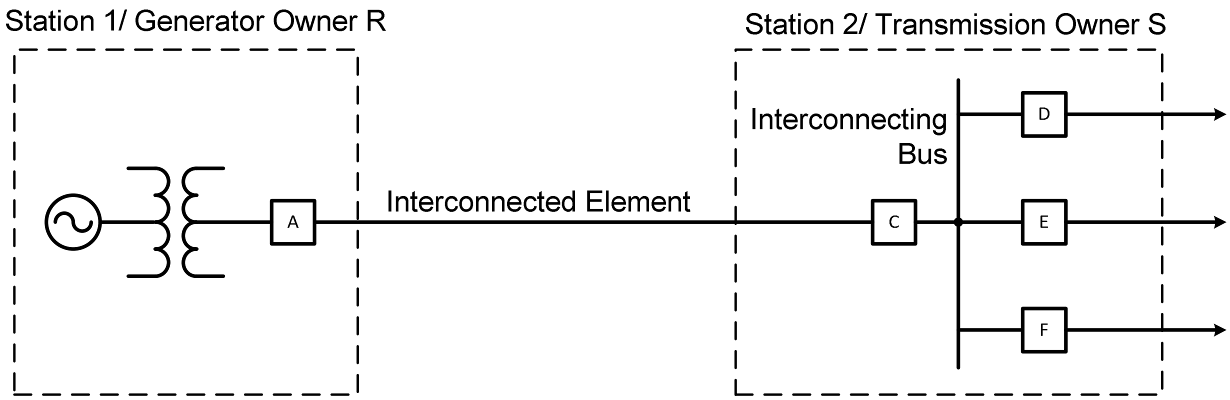
Figure 1



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

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

Figure 2

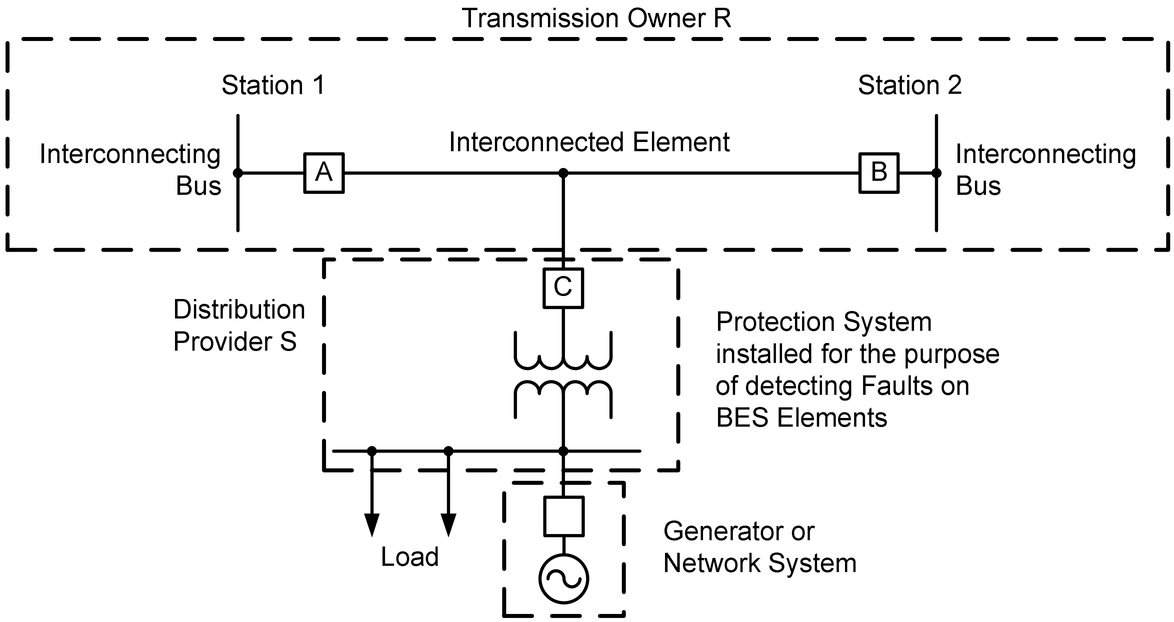


In Figure 2 above, the ~~Interconnected~~Interconnecting Element between the Transmission Owner and the Generator Owner is the transmission line or bus between Breakers A and C.

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

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

Figure 3



In Figure 3 above, the ~~Interconnected~~Interconnecting Element between the Transmission Owner and the Distribution Provider is the transmission line (or tap) between Breaker C and the point of connection to the line between Breakers A and B.[p4]

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

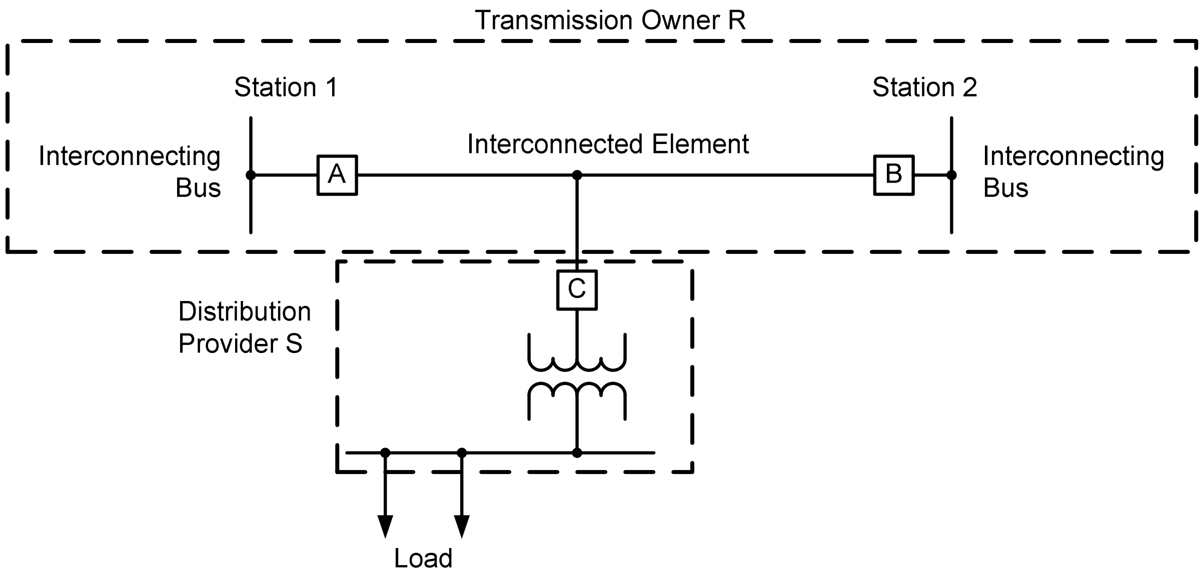
Notes:

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

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

The configuration above is an example excluded from this standard because the Distribution Provider S does not own Protection Systems installed for the purpose of detecting Faults on BES Elements[p5]. Additionally, the Transmission Owner R is excluded because the Protection Systems at Breakers A and B are owned by the same registered functional entity[am6].

Figure 4



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

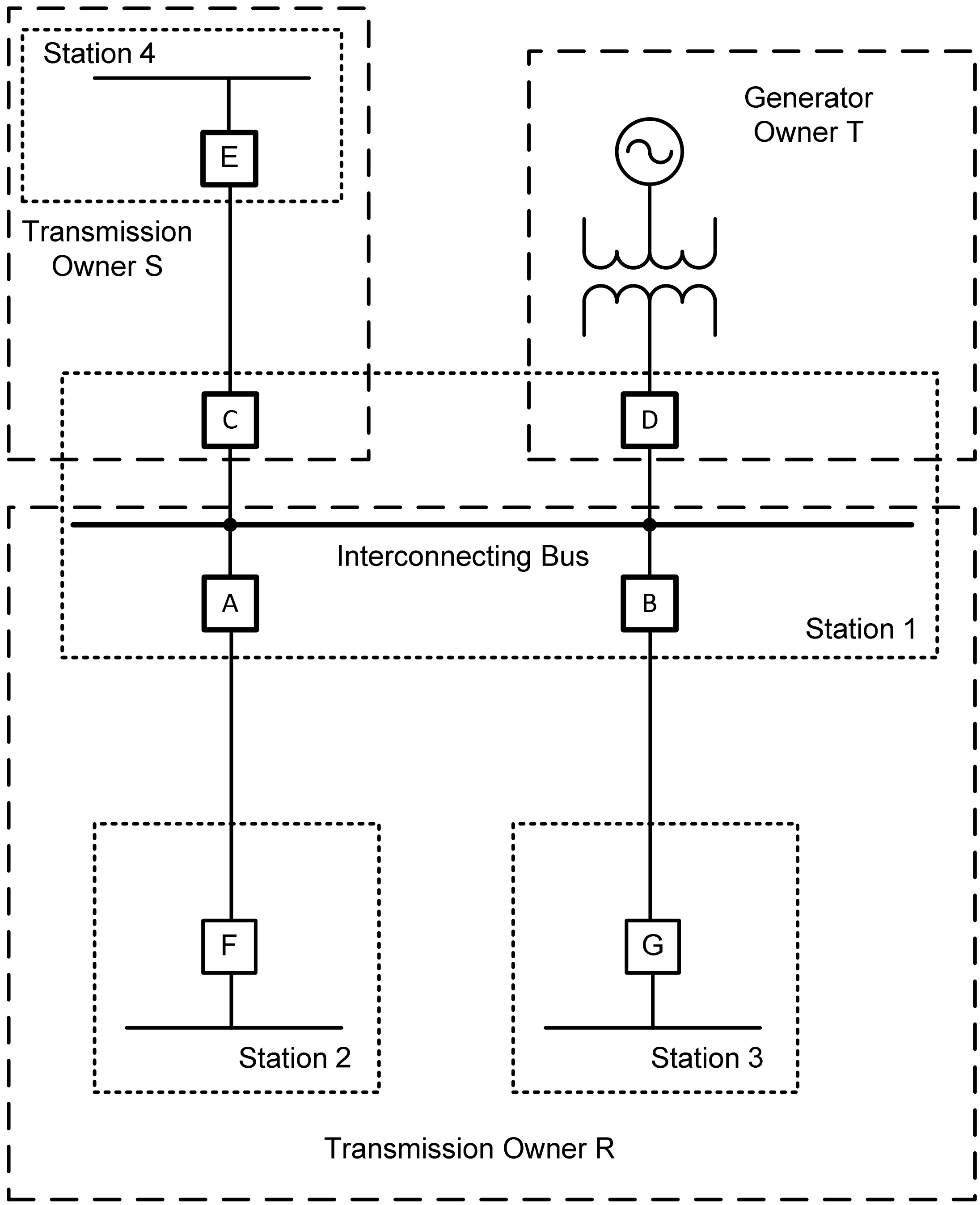
The configuration above is an example excluded from this standard because the Distribution Provider S does not own Protection Systems installed for the purpose of detecting Faults on BES Elements[p7]. Additionally, the Transmission Owner R is excluded because the Protection Systems at Breakers A and B are owned by the same registered functional entity.

~~**Note:** No specific PSCS is required per this standard for this example since the Protection System at the Distribution Provider's substation is not installed for the purpose of detecting Faults on BES Elements~~[p8]~~.~~

Figure 5

Transmission/Generation Facility with Multiple Owners[am9]

Note: In a large majority of cases, Figure 2 would be applicable for most generator interconnections. In Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T. [p10]



~~In~~ Figure 5 above illustrates~~,~~ the ~~Interconnected~~Interconnecting Elements between the Transmission Owners R and S and Generator Owner T ~~is the common Transmission bus~~. In this example, Transmission Owner S and Generator Owner T are not directly

~~interconnected~~interconnecting to each other at Station 1. All direct interconnections are between Owner R and each of the other Owners connected to the common bus at Station 1.

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

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

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

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

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

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

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

Consideration of Comments

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

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

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

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

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

Index to Questions, Comments, and Responses

The Industry Segments are:

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

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

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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Matt Goldberg	ISONE	NPCC	2

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

2. Ben Li	IESO	NPCC	2
3. Lori Spence	MISO	MRO	2
4. Charles Yeung	SPP	SPP	2
5. Matt Morais	ERCOT	ERCOT	2
6. Ali Mehremadi	CAISO	WECC	2

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

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

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

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

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

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

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

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

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

Additional Member	Additional Organization	Region	Segment Selection
1. William Smith	FirstEnergy Corp	RFC	1
2. Cindy Stewart	FirstEnergy Corp	RFC	3
3. Doug Hohlbaugh	Ohio Edison	RFC	4
4. Ken Dresner	FirstEnergy Solutions	RFC	5
5. Kevin Querry	FirstEnergy Solutions	RFC	6

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

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

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

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

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

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

From: Al McMeekin
To: "spcsdt@nerc.com"
Cc: "Juan Villar"
Subject: Email ballot regarding the use of a technical justification in Requirement R2 and the resulting redlined standard
Date: Wednesday, August 21, 2013 4:23:00 PM
Attachments: PRC-027-1_08212013_redline_V2_ahm.docx

Team,

Thank you all for your quick response to the email ballot. The vote tally was 7 – 1 in favor of removing the phrase "technically justify why a change in total bus Fault current does not affect the Protection System coordination" from Requirement R2. Consequently, I am sending you the representative redlined standard. I am not resending the response to comments document as I know each of you have it and there is no sense clogging your email system with another copy of it; however, I request that each of you review your responses and make any necessary edits based on this change. This is of course in addition to your current assignments. Thank you all and I will see you or talk with you next week.

Al

Subject: Email ballot regarding the use of a technical justification in Requirement R2

At our drafting team meeting last week, there was a great deal of discussion centered around removing the phrase "technically justify why a change in total bus Fault current does not affect the Protection System coordination" from Requirement R2. There was a motion made and seconded to remove the phrase because some team members believe there is a reliability benefit in notifying the other owners of a 10% change in Fault current at the interconnecting bus. The language below provides the basis for the removal.

Each owner of Protection Systems associated with Interconnecting Elements needs to be aware of a 10% change in Fault current at the interconnecting bus for the following reasons:

The Protection Systems owned by the notified entity may be affected by the change in Fault current even though the Transmission Owner performing the short circuit study has Protection Systems that are not affected by Fault current on the Interconnecting Element.
The conditions for which a technical justification for not completing a study in Requirement R1 was based may no longer be valid with the change in Fault current
The change in Fault current may affect Protection Systems other than the Protection Systems associated with the Interconnecting Element. Notifying the other owners of these changes may alert them to review their Protection System settings based on the noted impedance change(s) at the other end of the Interconnecting Element.

As decided at the meeting. I am providing this to you for your contemplation and your official vote. A vote to approve means that the phrase will be removed from the requirement and Requirement R2 will read as follows:

R2. For each Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months:

Please remember that this change does not impact any of the other requirements where the use of a technical justification is permissible.

Please reply to this email with your **VOTE** by 5 pm eastern time, Thursday August 22nd.

The voting options are:

Approve
Disapprove*
Abstain*

*Do you wish for your name to be noted in the minutes as a 'Disapprove' or 'Abstain' voter?

Al

____
Al McMeekin
Standards Developer, Standards
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Atlanta, GA 30326
404-446-9675 office | 803-530-1963 cell
Al.McMeekin@nerc.net
Reliability | Accountability

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Team Roster

Project 2007-06 System Protection Coordination Standard Drafting Team

	Participant	Company/Address	Vote
Chair	Philip Winston	Southern Company 62 Lake Mirror Road, Bin # 50061 Forest Park, Georgia 30297	Approve
Vice Chair	Bill Middaugh	Tri-State Generation & Transmission Association Inc. 1100 W. 116th Avenue Westminster, Colorado 80234	Approve
Member	David Cirka	National Grid 40 Sylvan Road Waltham, Massachusetts 02451	Approve
Member	Forrest Brock	Western Farmers Electric Cooperative 701 NE 7th Street Anadarko, OK 73005	Approve
Member	Samuel Francis	Oncor Electric Delivery 115 W. 7th Street Suite 3114 Fort Worth, Texas 76101	Approve
Member	Jeffrey Iler	American Electric Power 700 Morrison Road Gahanna, Ohio 43230	Approve
Member	William Waudby	Consumers Energy 1945 Parnall Road P14-707 Jackson, Michigan 49201	Approve
Member	Kevin Wempe	Kansas City Power & Light Co. 4400 E. Front Street Kansas City, Missouri 64120	Disapprove

From:	Wempe Kevin
To:	"Jeffrey W Iler"; Al McMeekin; spcsdt@nerc.com
Cc:	kthompson@itctransco.com
Subject:	RE: Removal of technically justify from R2
Date:	Monday, August 19, 2013 12:26:23 PM

See my comments below.

Thank you,

Kevin Wempe
Kansas City Power & Light
Subsidiary of Great Plains Energy
4400 E. Front St.
Kansas City, MO 64120-1039
Work Phone (816) 245-3778
Cell Phone (816) 719-9753

From: Jeffrey W Iler [mailto:jwiler@aep.com]
Sent: Thursday, August 15, 2013 2:25 PM
To: Al McMeekin; spcsdt@nerc.com
Cc: kthompson@itctransco.com
Subject: Removal of technically justify from R2

Here is a draft of the justification for the proposed change to Requirement R2.

The drafting team has decided to remove the phrase "technically justify why Fault current does not affect the Protection System coordination" from requirement R2 because this may create a reliability gap.
Each owner of the Protection System associated with the Interconnecting Element needs to be aware of a 10% change in fault current for following reasons:

- Their Protection Systems may be affected by the change in fault current even though the TO performing the short circuit study has Protection Systems that are not affected by fault current on the interconnecting element If the GO or TO feels that they have a technical justification for Requirement R2 and they inform the other party as you change it in Requirement R4 what issues are you trying to address? This is not a very convening agreement.
- The conditions under which a technical justification was based, for not completed a study in Requirement R1, may no longer be valid with the change in fault current. Requirement R1 require an initial study the Technical Justification can only be after the first study is valid, the technical justification in R1 part 1.1.2 is for if the fault current changes by 10% and no study is going to be performed. Not all utilities set overcurrent with only a 20% margin at the beginning especially those that have communication on the line, at least this is our experience.
- The change in fault current may affect Protection Systems other than the Protection Systems associated with the Interconnecting Element. This standard applies to the interconnection and this that effect the interconnection,

if changes are made to the protection systems associated with the interconnection that information is required to be provided to the owner of that interconnection. No one believes this standard applies to internal lines.

Jeff Iler
Protection & Control Engineering
American Electric Power
614-552-2119 (office)
614-949-7323 (cell)

Standards Development Process Participant Conduct Policy

I. General
To ensure that the standards development process is conducted in a responsible, timely and efficient manner, it is essential to maintain a professional and constructive work environment for all participants. Participants include, but are not limited to, members of the standard drafting team and observers.

Consistent with the NERC Rules of Procedure and the NERC Standard Processes Manual, participation in NERC's Reliability Standards development balloting and approval processes is open to all entities materially affected by NERC's Reliability Standards. In order to ensure the standards development process remains open and to facilitate the development of reliability standards in a timely manner, NERC has adopted the following Participant Conduct Policy for all participants in the standards development process.

II. Participant Conduct Policy
All participants in the standards development process must conduct themselves in a professional manner at all times. This policy includes in-person conduct and any communication, electronic or otherwise, made as a participant in the standards development process. Examples of unprofessional conduct include, but are not limited to, verbal altercations, use of abusive language, personal attacks or derogatory statements made against or directed at another participant, and frequent or patterned interruptions that disrupt the efficient conduct of a meeting or teleconference.

III. Reasonable Restrictions in Participation
If a participant does not comply with the Participant Conduct Policy, certain reasonable restrictions on participation in the standards development process may be imposed as described below.
If a NERC Standards Developer determines, by his or her own observation or by complaint of another participant, that a participant's behavior is disruptive to the orderly conduct of a meeting in progress, the NERC Standards Developer may remove the participant from a meeting. Removal by the NERC Standards Developer is limited solely to the meeting in progress and does not extend to any future meeting. Before a participant may be asked to leave the meeting, the NERC Standards Developer must first remind the participant of the obligation to conduct himself or herself in a professional manner and provide an opportunity for the participant to comply. If a participant is requested to leave a meeting by a NERC Standards Developer, the participant must cooperate fully with the request.

Similarly, if a NERC Standards Developer determines, by his or her own observation or by complaint of another participant, that a participant's behavior is disruptive to the orderly conduct of a teleconference in progress, the NERC Standards Developer may request the participant to leave the teleconference. Removal by the NERC Standards Developer is limited solely to the teleconference in progress and does not extend to any future teleconference. Before a participant may be asked to leave the teleconference, the NERC Standards Developer must first remind the participant of the obligation to conduct himself or herself in a professional manner and provide an opportunity for the participant to comply. If a participant is requested to leave a teleconference by a NERC Standards Developer, the participant must cooperate fully with the request. Alternatively, the NERC Standards Developer may choose to terminate the teleconference.

At any time, the NERC Director of Standards, or a designee, may impose a restriction on a participant from one or more future meetings or teleconferences, a restriction on the use of any NERC-administered list server or other communication list, or such other restriction as may be reasonably necessary to maintain the orderly conduct of the standards development process. Restrictions imposed by the Director of Standards, or a designee, must be approved by the NERC General Counsel, or a designee, prior to implementation to ensure that the restriction is not unreasonable. Once approved, the restriction is binding on the participant. A restricted participant may request removal of the restriction by submitting a request in writing to the Director of Standards. The restriction will be removed at the reasonable discretion of the Director of Standards or a designee.

Any participant who has concerns about NERC's Participant Conduct Policy may contact NERC's General Counsel.