Meeting Notes

Project 2007-06 System Protection Coordination Standard Drafting Team

November 3-6, 2014

Oncor HQ
Ft. Worth, TX

Administrative

The meeting was brought to order by the chair Phil Winston at 1:00 p.m. CT on Monday, November 3, 2014. Sam Francis provided the team with building and safety information/logistics. Each participant was introduced; those in attendance were:

Name	Company	Member/ Observer	In Person	Conference Call/Web
Philip Winston, Chair	Southern Company	Member	X	
Bill Middaugh, Vice Chair	Tri-State G & T Association, Inc.	Member	X	
Forrest Brock	Western Farmers Electric Cooperative	Member	X	
David Cirka	National Grid	Member		X
Samuel Francis	Oncor	Member	X	
Jeffery Iler	American Electric Power	Member	X	
Kevin Wempe	Kansas City Power & Light Co.	Member	X	
Al McMeekin	NERC Staff	Member	X	
Lacey Ourso	NERC Staff	Observer		X
Armin Klusman	Centerpoint Energy	Observer	X	
Brian Clowe	Centerpoint Energy	Observer	X	
Don Sevcik	Centerpoint Energy	Observer	X	
Juan Villar	FERC Staff	Observer	X	

1. **Determination of Quorum**
   The rule for NERC Standard Drafting Team (SDT) states that a quorum requires two-thirds of the voting members of the SDT. Quorum was achieved as 7 of the 7 total members were present.

2. **NERC Antitrust Compliance Guidelines and Public Announcement**
   The NERC Antitrust Compliance Guidelines and public announcement were delivered.

3. **Review Team Roster**
   The team reviewed the team roster and confirmed that it was accurate and up to date.

Agenda

1. **Review developments since last meeting**
   Al McMeekin reviewed the developments since the last meeting focusing on the discussions with members of FERC staff from the Office of Electric Reliability and the drafting teams' response. FERC staff raised concerns that the last posted draft of PRC-027-1 did not address the coordination of Protection Systems within a Transmission Owner's footprint, referred to as "internal" or "intra-entity" Protection Systems. The drafting team responded to FERC's concerns by developing a preliminary draft 5 of PRC-027-1 and posted the new standard for a 21-day informal comment period from October 1 through October 21. Draft 5 of PRC-027-1 modifies the applicability of the standard to include "Protection Systems installed for the purpose of detecting Faults on BES Elements, and isolating those faulted Elements," whereas, prior drafts of the standard limited the applicability to "Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements." This change to the applicability covers the coordination of Protection Systems for all "internal" or "intra-entity" connections between BES Elements. The prior drafts of PRC-027-1 would not have been easily adaptable to this change, and as a result, the drafting team has altered its approach in the draft. The draft now consists of two proposed requirements.

   Requirement R1 mandates an entity to implement a process to coordinate its BES Protection Systems, and stipulates certain attributes that must be included in the documented coordination process. Because entities' Protection System designs and philosophies vary greatly, the drafting team has included necessary flexibility in developing the coordination processes.

   Requirement R2 mandates an entity have documentation, within 60 calendar months after the effective date of the standard, that the Protection Systems for the Elements specified in Requirement R2 are coordinated. Requirement R2 is a one-time performance requirement necessary to establish a baseline of coordination.

2. **Discuss revisions and prepare draft standard**
   Based on stakeholder input, the drafting team made numerous changes to the standard. The changes are all preliminary as the team did not finish reviewing and discussing all of the suggestions received. Please refer to the draft standard attached.

3. **Future Meetings**
   - December 1 - 4, 2014 | Fort Worth

4. **Adjourn**
   The meeting adjourned at 12:25 p.m. CT on Thursday, November 6, 2014.

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.
7. Draft 3 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from June 4 – July 3, 2013.
8. Draft 4 of PRC-027-1 was posted for a 45-day formal comment and ballot from September 18 – November 1, 2013. Note: Posting and ballot postponed as of September 27, 2013.
9. Draft 4 of PRC-027-1 was re-posted for a 45-day formal comment and ballot from November 4 – December 18, 2013. Note: Ballot reached quorum on December 31, 2013.
10. Draft 5 of PRC-027-1 was posted for a XX-day informal comment from October 1 – October 21, 2014.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: “To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection System components operate in the intended sequence during Faults.” This standard incorporates and clarifies the coordination aspects of Requirements R3 and R4 from PRC-001-1.1. FERC raised significant concerns on the last posted draft that warranted further discussions with members of FERC staff from the Office of Electric Reliability. The SPCSDT composed draft 5 of PRC-027-1 based on the feedback from those discussions, and is soliciting stakeholder feedback on this latest draft of PRC-027-1 during a XX-day informal comment period.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period	December 2014-February 2015
Final Ballot	March 2015
BOT adoption	May 2015

Effective Dates

PRC-027-1 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 System Protection Coordination	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved.

The following terms are defined for use only within PRC-027-1:

Term: Interconnecting Element

A Bulk Electric System (BES) Element that electrically joins Facilities:

a) owned by separate Registered Entities, or

b) assigned to different functional entities (Transmission Owner, Generator Owner, or Distribution Provider) of the same Registered Entity

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

Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. Other protection issues, 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-006-2 by Project 2008-02, Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)
- Undervoltage Load shedding programs are addressed in PRC-010-1 by Project 2008-02, Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS).
- Generator performance during declined frequency and 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 addressed in PRC-019-1 by Project 2007-09, Generator Verification.
- Transmission relay loadability is addressed in PRC-023-3 by Project 2010-13.2 Phase 2 Relay Loadability: Generation.
- Generator relay loadability is addressed in PRC-025-1 by Project 2010-13.2 Phase 2 Relay Loadability: Generation.
- Protective relay response during power swings will be addressed by Project 2010-13.3, Phase 3 of Relay Loadability: Stable Power Swings.
- Protection System Misoperations (including those caused by coordination issues) are addressed in PRC-004-3, Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPCSDT contends 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.

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

A. Introduction

1.4 Title: Coordination of Protection System Performance During Faults

1.4 Number: PRC-027-1

1.4 Purpose: To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.

1.4 Applicability:

.4. Functional Entities:

.4.1 Transmission Owner

4.1.2 Generator Owner

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

.5. Facilities:

.5.1 Protection Systems installed for the purpose of detecting Faults on BES Elements, and isolating those faulted Elements

1.4 Effective Date: See Implementation Plan

1.4 Definitions:

<u>Interconnecting Element</u>

A Bulk Electric System (BES) Element that electrically joins Facilities:

a) owned by separate Registered Entities, or

b) assigned to different functional entities (Transmission Owner, Generator Owner, or Distribution Provider) of the same Registered Entity

B. Requirements and Measures

Rationale for Requirement R1:

The System Protection Coordination Standard Drafting Team (SPCSDT) recognizes the importance of having coordinated Protection Systems. The stated purpose of this standard is: To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults. Requirement R1 captures this intent by requiring an entity to implement a coordination process that, when followed, will facilitate consistent results for coordinating their BES Protection Systems.

Part 1.1 Reviewing and updating the information ensures that the process of developing or reviewing settings is completed using accurate up-to-date information. Examples of information that potentially need to be reviewed are: short-circuit databases; line and transformer impedances; station configurations; current and voltage transformer ratios; adjacent Protection System settings; and relay and control functional drawings.

Part 1.2 Entities are required to have a process to review existing Protection System settings. This requirement provides the flexibility to use either Fault-based or time-based methodologies or a combination of the two.

A change in Fault current may indicate that a review of the Protection System settings is necessary. Such changes could result from an accumulation of incremental changes over time. The Fault current values used in the percent change calculation are typically determined with maximum generation and all Facilities in service. The requirement provides the entity the flexibility based on its protection philosophy to choose a threshold not to exceed 15 percent from an entity-established Fault current baseline. The drafting team contends that a value larger than a 15 percent change merits a review because the built-in margin of the Protection System has been significantly reduced.

For simplicity, some entities may choose a time-based methodology to review Protection System settings.

As a third option, an entity may choose to apply a combination of the two review methodologies based on criteria such as voltage level, Protection System application, etc.

Part 1.3 A quality review of the Protection System settings facilitates minimizing the introduction of human error into the development of the Protection System settings. Quality reviews can take various forms such as peer reviews, automated checking programs, entity-developed review procedures, etc.

Part 1.4 The reliability objective of this requirement is to ensure that the proposed Protection System settings are provided to the other owner(s) of the Protection Systems associated with Interconnecting Element(s) so they can identify and address any coordination issues.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: TBD] [Time Horizon: TBD]* PW

1.1. A method to review and update the information required to develop Protection System settings. SF

1.2. A review of existing Protection System settings based on: KW

- Changes in either three-phase or phase-to-ground Fault current, not to exceed 15 percent, reviewed at least once every 6 calendar years, or
- A time interval, not to exceed 6 calendar years, or
- A combination of the above

1.3. A quality review of the Protection System settings. FB

1.4. Additionally, for Interconnecting Elements: JI

1.4.1 A procedure to communicate the proposed Protection System settings associated with Interconnecting Elements with other Transmission Owners, Generator Owners, and Distribution Providers, which includes requesting both a review of the proposed settings, and a return notification of any identified coordination issues or affirmation that no coordination issues were identified.

1.4.2 A procedure to verify that any identified coordination issue(s) associated with proposed Protection System settings on Interconnecting Elements are addressed prior to implementation.

M1. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the responsible entity has implemented its process to coordinate its BES Protection Systems, in accordance with Requirement R1 and its Parts.

Rationale for Requirement R2: Requirement R2, Parts 2.2, 2.3, and 2.4 are one-time performances necessary to establish a baseline of coordination assessment of Protection Systems. Requirement R2 mandates an entity have documentation, within the time frames identified in the requirement, that the Protection Systems for the Elements specified in Requirement R2 are coordinated. The drafting team has provided a tiered approach for this assessment to ensure Facilities that represent higher reliability risks are addressed first. Monitored Facilities of an IROL (defined as a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System) are to be reviewed within 3 calendar years. The drafting team allocated 6 calendar years as the review time frame for Interconnecting Elements. The drafting team excluded generating resources less than 75 MVA based on their minimal impact to the reliability of the BES.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall review the Protection System settings for the purpose of assessing the coordination of the Protection Systems applied on the following: *[Violation Risk Factor: TBD] [Time Horizon: TBD]* *BM*

2.1. Monitored Facilities of an existing Interconnection Reliability Operating Limit (IROL), within 3 calendar years of the effective date of this standard, or within 3 calendar years of the establishment of an IROL after the effective date of this standard.

2.2. Interconnecting Elements associated with Transmission Owners, within 6 calendar years of the effective date of this standard.

2.3. Interconnecting Elements associated with BES generating resource(s) with gross plant/facility aggregate nameplate rating greater than 75 MVA, within 6 calendar years of the effective date of this standard.

2.4. Interconnecting Elements associated with dispersed power producing resources that are designated as BES Facilities under Inclusion I4 of the BES definition within 6 calendar years of the effective date of this standard.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the responsible entity reviewed the applicable Protection System settings within the time frame(s) identified in Requirement R2.

C. Compliance

1.4 Compliance Monitoring Process

.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.

.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 Interconnecting Element shall each keep data or evidence to show compliance with Requirements R1, and R2, and Measures M1 and M2, 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 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.

.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

.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						
R2						
R3						

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Definition used in this standard:

Interconnecting Element

A Bulk Electric System (BES) Element that electrically joins Facilities:

a) owned by separate Registered Entities, or

b) assigned to different functional entities (Transmission Owner, Generator Owner, or Distribution Provider) of the same Registered Entity.

Purpose:

To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.

This standard requires that entities implement a process to to coordinate its BES Protection Systems to operate in the intended sequence during Faults. The goal of the this process is to verify that the Protection Systems intended for sensing Faults will operate in the intended sequence for internal and external Faults on BES Elements.

Requirement R1:

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall implement a process to coordinate its BES Protection Systems to operate in the intended sequence during Faults. The process shall include, at a minimum:

This requirement directs the applicable entities to implement a process to perform a Protection System Coordination Study (PSCS) for every Interconnecting Element to verify coordination of existing Protection Systems where no PSCS exists; or when Facility configuration changes that modify the conditions used in a PSCS 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 (SPCSDT) 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 documenting that existing or proposed Protection Systems operate in the intended sequence for clearing Faults."

PSCSs comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in PSCSs typically include maximum generation with the transmission system under normal and 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.

R1.1 A method to review and update the information required to develop Protection System settings.

Reviewing and updating the information ensures that the process of developing or reviewing settings is completed using accurate up-to-date information. Examples of information that potentially need to be reviewed are: short-circuit databases; line impedance, bank impedances; station configurations; current transformer and voltage transformer ratios, adjacent Protection System settings; relay drawings; etc.

R1.2 A review of existing Protection System settings based on:

- Changes in either three-phase or phase-to-ground Fault current, not to exceed 15 percent, reviewed at least once every 6 calendar years, or
- A time interval, not to exceed 6 calendar years, or
- A combination of the above

Entities are required to have a process to review existing Protection System settings. This requirement provides the flexibility to use either Fault-based or time-based methodologies or a combination of the two.

A change in Fault current may indicate that a review of the Protection System settings is necessary. Such changes could result from an accumulation of incremental changes over time. The Fault current values used in the percent change calculation are typically determined with maximum generation and all Facilities in service. The requirement provides the entity the flexibility based on its protection philosophy to choose a threshold not to exceed 15 percent from an entity-established Fault current baseline. This change applies to either three-phase or phase-to-ground Fault current.

For simplicity, some entities may choose a time-based methodology to review Protection System settings.

As a third option, an entity may choose to apply a combination of the two review methodologies based on criteria such as voltage level, Protection System application, etc.

R1.3 A quality assurance review of the Protection System settings.

A quality review of the Protection System settings reduces the possibility of human error being introduced into the development of the Protection System settings. A quality review can take various forms such as peer review, automated checking programs, entity-developed review procedures, etc.

R1.4 Additionally, for Interconnecting Elements:

1.4.1 A procedure to communicate the proposed Protection System settings associated with Interconnecting Elements with other Transmission Owners, Generator Owners, and Distribution Providers requesting review and either notification of any identified coordination issues or affirmation that no coordination issues were identified.

1.4.2 A procedure to verify any identified coordination issue(s) associated with proposed Protection System settings on Interconnecting Elements are addressed prior to implementation.

R2 Each Transmission Owner, Generator Owner, and Distribution Provider shall review the Protection System settings for the purpose of assessing the coordination of the Protection Systems applied on the following: *[Violation Risk Factor: TBD] [Time Horizon: TBD] BM*

2.1. Monitored Facilities of an existing Interconnection Reliability Operating Limit (IROL), within 3 calendar years of the effective date of this standard, or within 3 calendar years of the establishment of an IROL after the effective date of this standard.

2.2. Interconnecting Elements associated with Transmission Owners, within 6 calendar years of the effective date of this standard.

2.3. Interconnecting Elements associated with BES generating resource(s) with gross plant/facility aggregate nameplate rating greater than 75 MVA, within 6 calendar years of the effective date of this standard.

2.4. Interconnecting Elements associated with dispersed power producing resources that are designated as BES Facilities under Inclusion I4 of the BES definition within 6 calendar years of the effective date of this standard.

This requirement directs the applicable entities to perform a Protection System Coordination Study (PSCS) for every Interconnecting Element to verify coordination of existing Protection Systems where no PSCS exists; or when Facility configuration changes that modify the conditions used in a PSCS 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 (SPCSDT) 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 documenting that existing or proposed Protection Systems operate in the intended sequence for clearing Faults."

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

Part 1.1.1:

The drafting team contends applicable entities should have a documented PSCS for each Interconnecting Element to validate the Protection Systems associated with those Interconnecting Elements perform in a manner consistent with the purpose of this Standard. Additionally, the drafting team contends 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 mis-coordination between owners of Facilities associated with 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.

Part 1.1.2:

After notification of an identified 10% or greater change in Fault current (single line to ground and 3-phase for the interconnecting bus(es) 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 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 contends 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.

Part 1.1.3:

After proposing or being notified of a change at a Facility associated with the 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 contends 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 address any identified coordination or technical justification issue(s) prior to implementing any proposed change(s) or addition(s) as stipulated by Requirement R5.

Part 1.1.4:

After being notified of a change at a Facility associated with the Interconnecting Element associated with Requirement R3, Part 3.3, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team contends 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.

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)
    - Local breaker failure schemes
4. Definite time and/or time overcurrent elements that remain coordinated regardless of Fault current changes.

Requirement R1, Part 1.2 directs the entity performing the PSCS to provide a summary of the study results or a technical justification to the affected Interconnecting Element owner(s). The drafting team contends 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 Interconnecting Element(s). (Note: In cases where a single group performs an overall coordination study for every terminal of a given Interconnecting Element, a single document that meets the requirements for a summary of the results of the PSCS would be sufficient for use by all Registered Entities.) The following inputs and results of a PSCS 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 were reviewed for coordination, 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 necessary to achieve coordination.

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 perform a periodic review of Fault currents. The Fault current values used in the percent change calculation are typically determined with maximum generation and all Facilities in service.

Requirement R2, Part 2.1 directs the Transmission Owner to calculate the percent change between the Fault current values used in the most recent PSCS and the present Fault current values. The drafting team contends that 60 calendar months is an appropriate interval for reviewing Fault currents. The drafting team contends 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 further directs the Transmission Owner to, within 90 calendar days, inform each owner of the Facility associated with the Interconnecting Element when the percent change calculations indicate that 10% changes in Fault current have occurred at the interconnecting bus(es). The drafting team contends the 90-calendar day time frame associated with this requirement is reasonable for providing the Fault current information to the 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 calculating the Fault current percent change because they perform the short circuit studies or have access to short circuit studies performed by other entities. Generator data (including data provided by Distribution Providers) is incorporated into the short circuit models.

In cases where a single group performs the Fault current change calculation in Requirement R2, Part 2.1 and also performs the PSCS for every terminal for a given Interconnecting Element, Requirement R2, Part 2.2 may not be applicable.