NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Meeting Notes

Project 2007-06 System Protection Coordination Standard Drafting Team

December 1-4, 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, December 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	Observer	X	
Lacey Ourso	NERC Staff	Observer		X
Rob Delsman	Entergy	Observer		X
Armin Klusman	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. **Develop draft standard**

   The drafting team continued to work on all aspects of the draft standard and associated documents. There was a great deal of discussion surrounding Requirement R2 being a one-time performance requirement as the team was against including such a requirement in a results-based standard. The team unanimously decided to remove the requirement and replace it with a new Requirement R2 that mandates entities implement the process established in Requirement R1 to ensure a consistent approach to the development of Protection System settings.

   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 implement the process developed in accordance with Requirement R1. Implementing the process ensures a consistent approach to the development of Protection System settings such that BES Protection Systems operate in the intended sequence during Faults.

2. **Next steps**

   Long-time SDT member David Cirka with National Grid tendered his resignation from the team effective immediately after the meeting ended due to significant work-related responsibilities.

   Al McMeekin and Phil Winston made assignments to the team to continue to enhance the wording of the rationales and supplemental materials. Work products will be shared via email and reviewed by all team members. Al McMeekin is completing the VRF/VSL Justification document, the implementation plan for PRC-027-1 and PRC-001-3, and the mapping document. The standard would be posted in early 2015. Please refer to the redline of the draft standard attached.

3. **Future Meetings**

   - TBD after posting

4. **Adjourn**

   The meeting adjourned at 12:00 p.m. CT on Thursday, December 4, 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 21-day informal comment from October 1 – October 21, 2014.
11. Draft 5 of PRC-027-1 was posted for a 45-day formal comment and ballot from…

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. Once the posting and balloting of draft 4 were completed, members of FERC staff from the Office of Electric Reliability raised significant concerns with the standard that warranted further discussions. The SPCSDT composed draft 5 of PRC-027-1 based on the feedback from those discussions, and solicited stakeholder feedback during a 21-day informal comment period from October 1 – October 21, 2014. After considering the comments received, the drafting team is posting draft 5 of PRC-027-1 for formal comment period and ballot.

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

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 Glossary of Terms Used in NERC Reliability Standards are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved.

Protection System Issues 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..
- Undervoltage Load shedding programs are addressed in PRC-010-1.
- Generator performance during declined frequency and voltage excursions is addressed in PRC-024-1.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-1.
- Transmission relay loadability is addressed in PRC-023-3.
- Generator relay loadability is addressed in PRC-025-1.
- Protective relay response during stable power swings is addressed in PRC-026-1.
- Protection System Misoperations (including those caused by coordination issues) are addressed in PRC-004-3.

The SPCSDT contends that including aspects of protection coordination other than Fault 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. **Title:** Coordination of Protection System Performance During Faults
2. **Number:** PRC-027-1
3. **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.
4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

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

   4.2 Facilities:

   Protection Systems installed for the purpose of detecting Faults on BES Elements, and isolating those faulted Elements
5. **Effective Date:** See Implementation Plan

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 establish a process that, when followed, will facilitate consistent results for developing settings for its BES Protection Systems.

Part 1.1 Reviewing and updating the information required to coordinate Protection Systems 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. This requirement provides the entity the flexibility, based on its protection philosophy, to choose a threshold of deviation (not to exceed 15 percent) from an entity-established Fault current baseline. The drafting team contends that a 15 percent change merits a review because with this amount of Fault current change, the designed-in margin of the Protection System settings has likely been reduced to a point where coordination may be affected under certain Fault conditions.

As a second option, entities may choose a time-based methodology for reviewing existing Protection System settings. This provides the entity the flexibility to choose a review interval up to six calendar years.

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.

For Part 1.2, the drafting team assigned a 6 calendar year timeframe for a Fault current comparison or Protection System settings review to ensure any incremental changes that could affect Protection System settings are identified. This timeframe also corresponds to the maximum allowable maintenance period established for electromechanical and lockout relays which would allow settings revisions to be included with the associated maintenance.

Part 1.3 A quality review of the Protection System settings serves to minimize the introduction of human error into the development of the Protection System settings and ensures the settings produced meet an entity's design specifications for Protection System performance. Peer reviews, automated checking programs, and entity-developed review procedures, are all examples of quality reviews.

Part 1.4 The reliability objective of this requirement is to ensure that the proposed Protection System settings are communicated to the other owner(s) of the Protection Systems associated with BES Elements that electrically join Facilities that are either owned by separate Registered Entities, or that are assigned to different functional entities (Transmission Owner, Generator Owner, or Distribution Provider) of the same Registered Entity, so any coordination issues can be identified and addressed prior to implementation.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish 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: High] [Time Horizon: Long-term Planning]*

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

1.2. 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

1.3. A quality review of the Protection System settings.

1.4. For BES Elements that electrically join Facilities that are either owned by separate Registered Entities, or that are assigned to different functional entities (Transmission Owner, Generator Owner, or Distribution Provider) of the same Registered Entity, procedures to:

1.4.1 Communicate the proposed Protection System settings with the other Transmission Owners, Generator Owners, and Distribution Providers.

1.4.2 Review proposed Protection System settings provided by other Transmission Owners, Generator Owners, and Distribution Providers, and respond regarding the proposed settings. The response should identify any coordination issues or affirm that no coordination issued were identified.

1.4.3 Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated 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 established a process to develop settings for its BES Protection Systems, in accordance with Requirement R1.

Rationale for Requirement R2: Implementing the process established in Requirement R1 ensures a consistent approach to the development of Protection System settings such that BES Protection Systems operate in the intended sequence during Faults.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement the process established in accordance with Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the responsible entity implemented the process established in accordance with Requirement R1.

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 Protection Systems designed to detect Faults on BES Elements 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.

1.3 Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

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	**Long-term Planning**	**High**	N/A	N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include one Part.	The responsible entity established a process in accordance with Requirement R1, but failed to include two or more Parts. OR The responsible entity failed to establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults.
R2	**Operations Planning**	**High**	N/A	N/A	The responsible entity implemented the process established in accordance with Requirement R1, but failed to implement one Part.	The responsible entity implemented the process established in accordance with Requirement R1, but failed to implement two or more Parts. OR The responsible entity failed to implement a process to develop

						settings for its BES Protection Systems to operate in the intended sequence during Faults.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee – Technical Reference Document "Power Plant and Transmission System Protection Coordination" (the most current version).

NERC System Protection and Control Task Force – Assessment of Standard PRC-001-0 – System Protection Coordination (December 7, 2006)

NERC System Protection and Control Task Force – The Complexity of Protecting Three-Terminal Transmission Lines (September 2006)

Guidelines and Technical Basis

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 establish and implement a process to coordinate their BES Protection Systems to operate in the intended sequence during Faults.

Requirement R1:

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults.

This requirement directs the applicable entities to establish a process to develop settings for coordinating its BES Protection Systems such that they operate in the intended sequence during Faults. The drafting team contends the items included as elements of the process are key to ensuring the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors in the development of these settings.

In developing this Standard, the System Protection Coordination Standard Drafting Team (SPCSDT) referenced various publications that discuss protective relaying theory and application. The following description of "coordination of protection" is 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."*

The drafting team acknowledges that entities may have differing technical criteria for the development of Protection System settings based on their own internal tolerances. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge. As such, a single definition or criteria for 'Protection System coordination' is not practical.

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

Two important studies used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers are the short circuit and protective device coordination studies. Having a method of reviewing and updating information to make sure it is correct in short circuit studies and protective device coordination studies is necessary to guarantee that these two studies accurately reflect the physical power system being considered in the development of Protection System relay settings. The results of the studies are only as accurate as the information that their calculations are based on.

A short circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. The results of a short circuit study are used as the basis for protective device coordination studies. Because a short circuit study should, as accurately as possible, model the actual network it is representing in order to calculate true Fault currents, the method of the review and update of information for the short circuit study might include the following:

1. A review of applicable BES line, transformer, and generator impedances to verify they are correct.
2. A review of the network model to confirm the network in the study accurately reflects the configuration of the actual system, or how the system will be configured when the proposed relay settings are installed.
3. A review of interconnected Transmission Owner, Generator Owner, or Distribution Provider's information to determine whether their Systems are correctly modeled in the short circuit study.

A protective device coordination study is performed to determine the settings for protective relays to operate in the intended sequence during Faults. Protective device coordination studies are used to evaluate the application of protective devices, identify problem areas in the network, and determine solutions for existing or future device coordination.

A protective device coordination study should, as accurately as possible, model the actual or proposed protective relaying in the network. The method for reviewing and updating information for the protective device coordination study might include the following:

1. A review of current and voltage transformer ratios, Protection System settings and the relay manufacture's curve characteristics to ensure the information in the protective device coordination study is correct.
2. A review of the adjacent relay settings in the data base to ensure those settings coordinate with the relay settings under study.
3. A review of interconnected Transmission Owner, Generator Owner, or Distribution Provider's actual and proposed relay setting changes to determine whether they are accurately represented in the protective device coordination study.

Other information that may be of value includes engineering drawings such as single-line diagrams, three-line diagrams, and relay and control functional drawings.

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 deviation from an entity-established Fault current baseline. This baseline should include those Fault currents used for previous settings checks or where not available, the Fault current values from the short circuit study applicable at the time the standard goes into effect. These base line fault current values can be at the bus level or at the individual Element level.

An entity's selected threshold percentage criteria will likely depend on the tolerance level established within the entity's setting philosophy. The drafting team contends that a 15 percent change merits a review because with this amount of Fault current change, the designed-in margin of the Protection System settings has likely been reduced to a point where coordination may be affected under certain Fault conditions. This change applies to either three-phase or phase-to-ground Fault currents.

As a second option, an entity may choose a time-based methodology to review Protection System settings eliminating the necessity of a Fault current baseline. This provides the entity the flexibility to choose a review interval up to six calendar years.

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

The drafting team contends that 6 calendar years is an appropriate timeframe for a Fault current comparison or Protection System settings review to ensure any incremental changes that could affect Protection System settings are identified. This timeframe also corresponds to the maximum allowable maintenance period established for electromechanical and lockout relays which would allow settings revisions to be included with the associated maintenance.

R1.3 A quality 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 is any systematic process of verifying whether the settings produced meet the entity's specific requirements for Protection System performance. Peer reviews, automated checking programs, entity-developed review procedures, are all examples of quality reviews.

R1.4 For BES Elements that electrically join Facilities that are either owned by separate Registered Entities, or that are assigned to different functional entities (Transmission Owner, Generator Owner, or Distribution Provider) of the same Registered Entity, procedures to:

- **1.4.1** Communicate the proposed Protection System settings with the other Transmission Owners, Generator Owners, and Distribution Providers.
- **1.4.2** Review proposed Protection System settings provided by other Transmission Owners, Generator Owners, and Distribution Providers, and respond regarding the proposed settings. The response should identify any coordination issues or affirm that no coordination issued were identified.
- **1.4.3** Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation.

This requirement applies specifically to Protection Systems applied on Facilities that are either owned by separate Registered Entities, or that are assigned to different functional entities (Transmission Owner, Generator Owner, or Distribution Provider) of the same Registered Entity. 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 so they can identify and address any coordination issues prior to implementation.

Requirement R1, Part 1.4.1 mandates entities have a procedure to communicate proposed Protection System settings with other entities. These communications ensure that the other entities have the necessary information to review the settings and determine if there are any coordination issues.

Requirement R1, Part 1.4.2 mandates the entity receiving proposed Protection System settings have a procedure to review the settings and respond to the entity that initiated the proposed changes. This requirement ensures that the proposed settings are reviewed and the initiating entity receives a response. The response must include any identified coordination issues. However, if no coordination issues were identified in the review, a response is still required to affirm that no issues were identified.

Requirement R1, Part 1.4.3 mandates the entity have a procedure to verify any identified coordination issue(s) associated with proposed Protection System settings are addressed prior to implementation, thus minimizing any potential impact to BES reliability.

The drafting team recognizes there could be instances where coordination issues are identified that pose minimum risk to the reliability of the BES, and the entities agree to allow the unmitigated issue to remain. It is also recognized that coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. The drafting team also recognizes there are situations where entities' protection philosophies differ but they can agree that there were no identified coordination issues.

R2 Each Transmission Owner, Generator Owner, and Distribution Provider shall implement the process established in accordance with Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

This requirement directs the applicable entities to implement the process established in Requirement R1. Implementing the process ensures a consistent approach to the development of Protection System settings such that BES Protection Systems operate in the intended sequence during Faults. The drafting team contends the items included as elements of the process are key to ensuring the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors in the development of these settings.