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.

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." PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii). 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." With this change to the applicability, the coordination of Protection Systems for all "internal" or "intra-entity" connections between BES Elements are addressed.

Completed Actions	Date
Standard Authorization Request (SAR) posted for comment	June 11 – July 10, 2007
SAR approved	August 13, 2007
Draft 1 of PRC-001-2 posted for comment	September 11 – October 26, 2009
Draft 1 of PRC-027-1 posted for formal comment with ballot	May 21 – July 5, 2012
Draft 2 of PRC-027-1 posted for formal comment with ballot	November 16 – December 17, 2012
Draft 3 of PRC-027-1 posted for formal comment with ballot	June 4 – July 3, 2013.
Draft 4 of PRC-027-1 posted for formal comment with ballot	November 4 – December 31, 2013
Draft 5 of PRC-027-1 posted for informal comment	October 1 – October 21, 2014

Draft 5 of PRC-027-1 posted for formal comment with ballot	April 1 – May 15, 2015

Anticipated Actions	Date
10-day final ballot	June, 2015
NERC Board (BOT) adoption	August, 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A

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 receives Board adoption, the rationale boxes will be moved to the Supplemental Material 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 for PRC-027-1, Project 2007-06 System Protection Coordination.

B. Requirements and Measures

Rationale for Requirement R1:

Coordinated Protection Systems enhance BES reliability by reducing the risk of power system instability or Cascading by isolating the faulted equipment in a timely manner – leaving the remainder of the System operational and capable of withstanding the next contingency. When Faults occur, properly coordinated protection systems minimize the number of power system Elements removed from service and protect power system equipment from damage. 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 mandating an entity establish a process that, when followed, will facilitate consistent results for developing settings for its BES Protection Systems. The drafting team contends the parts listed below are essential elements of the coordination process.

Part 1.1 Reviewing and updating the information required to coordinate Protection Systems maximizes the likelihood that the process of reviewing and developing 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 Reviewing the affected Protection System settings when System changes occur maintains coordination. Examples of System changes are: new or revised Protection System installations, changes to a transmission system Element that alters any sequence or mutual coupling impedance, changes to generator unit(s) that result in a change in impedance, or changes to the generator step-up transformer(s) that result in a change in impedance.

Part 1.3 Periodically reviewing Fault current values and/or existing entity-designated Protection System settings maximizes the likelihood that small incremental changes to the power system have not altered the coordination of the Protection Systems. Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults. For example, a current differential scheme may not need to be included because changes in Fault current will not affect the coordination of this system. However, an instantaneous overcurrent element would need to be reviewed because changes in Fault current may cause this element to operate for Faults outside its zone of protection. Part 1.3 provides entities the flexibility to use a Fault current-based or a time-based methodology, or a combination of the two.

The Fault current-based option requires an entity to first establish a Fault current baseline for Protection Systems at the bus under study to be used as a control point for future Fault current studies. Fault current changes on the System are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. To minimize this risk, the drafting team chose a maximum Fault current deviation of 15 percent (as compared to the entity-established baseline) and a maximum time interval of six calendar years for the Fault current analysis to be performed. The drafting team contends these maximums provide an entity with latitude to choose a Fault current threshold and time interval that best matches its protection philosophy, Protection System maintenance schedule, or other business considerations. (See the Supplemental Materials section for more detailed discussion.)

As a second option, an entity may choose to establish a periodic review of its existing Protection System settings. The maximum time interval for the review is six calendar years. The drafting team assigned a six calendar year time interval because that corresponds to the maximum allowable maintenance period established for certain relays in PRC-005-2; consequently, this allows Protection System settings revisions to be included with associated maintenance.

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 application.

Part 1.4 A quality review of the Protection System settings minimizes the introduction of human error into the development of Protection System settings and helps to ensure the settings produced meet the 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 1.5 The coordination of Protection Systems associated with BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) is critical to the reliability of the BES. Communications among these entities is essential so potential coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

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: Medium] [Time Horizon: Long-term Planning]*

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

1.2. A review of Protection System settings affected by System changes.

1.3. A review of existing entity-designated[1] Protection System settings based on one of the following:

- **Periodic Fault current studies:** A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the bus under study, and evaluated in a time interval not to exceed six calendar years, or
- **Periodic review of Protection System settings:** A time interval, not to exceed six calendar years, or
- A combination of the above.

1.4. A quality review of the Protection System settings prior to implementation.

[1] Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults.

1.5. For new or revised Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, (Transmission Owners, Generator Owners, and Distribution Providers), procedures to:

1.5.1. Communicate the proposed Protection System settings with the other functional entities.

1.5.2. Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified.

1.5.3. 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 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 period(s) 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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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 completed and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	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 in accordance with Requirement R1.
R2.	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 the process established in accordance with Requirement R1.

D. Regional Variances

None.

E. 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)

Implementation Plan **(DELETE GREEN TEXT PRIOR TO PUBLISHING) A link should be added to the implementation plan and other important documents associated with the standard once finalized.**

Version History

Version	Date	Action	Change Tracking
1	TBD	Adopted by NERC Board of Trustees	New

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.

Coordinated Protection Systems enhance BES reliability by reducing the risk of power system instability or Cascading by isolating the faulted equipment in a timely manner – leaving the remainder of the System operational and capable of withstanding the next contingency. When Faults occur, properly coordinated protection systems minimize the number of power system Elements removed from service and protect power system equipment from damage. 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.

The drafting team also recognizes that the coordination of some Protection Systems may seem unnecessary, such as for a line that is protected by dual current differential relays. Where backup Protection Systems are enabled to operate based on current level or apparent impedance with some definite or inverse time delay, it is important to ensure those Protection Systems coordinate with other Elements' Protection Systems such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A method to review and update the information required to develop new or revised 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, represent 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 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.

Part 1.2 A review of Protection System settings affected by System changes.

Reviewing the affected Protection System settings when System changes occur maintains coordination. Examples of System changes are: new or revised Protection System installations, 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, or changes to the generator step-up transformer(s) that result in a change in impedance.

Part 1.3 A review of existing entity-designated Protection System settings based on one of the following:

Periodically reviewing Fault current values and/or existing entity-designated Protection System settings maximizes the likelihood that small incremental changes to the power system have not altered the coordination of the Protection Systems. Based on the Protection System design and/or susceptibility to changes in Fault current, an entity will designate what Protection Systems must be included in the review to ensure these Protection Systems continue to operate in the intended sequence during Faults. For example, a current differential scheme may not need to be included because changes in Fault current will not affect the coordination of this system. However, settings for an instantaneous overcurrent element would need to be reviewed because changes in Fault current may cause this element to operate for Faults outside its zone of protection. Based on stakeholder comments and industry knowledge, the drafting team chose two ‘triggers’ for initiating a review of existing Protection System settings. Entities have the flexibility to use a Fault current-based or a time-based methodology, or a combination of the two.

- (Option 1) A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the busunder study, and evaluated in a time interval not to exceed six calendar years, or Fault current changes on the System are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. To minimize this risk, the drafting team chose a maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) and a maximum time interval of six calendar years for the Fault current analysis to be performed. The drafting team contends these maximums provide an entity with latitude to choose a Fault current threshold and time interval that best matches its protection philosophy, Protection System maintenance schedule, or other business considerations. The Fault current-based option requires an entity to first establish a Fault current baseline to be used as a control point for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault currents, are typically determined with maximum generation and all Facilities assumed to be in service.

  The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect. These baseline Fault current values can be at the bus level or at the individual Element level. When performing the periodic Fault current comparison, the entity would continue to compare actual Fault current values gathered during the review against the originally established baseline values until a condition occurs that necessitates the establishment of a new baseline.

Example: Baseline is established at 10,000 amps. During the first short-circuit review, it is discovered that Fault current has increased to 11,250 amps (12.5 % change); consequently, no Protection System settings review is required since the increase is below 15% and the baseline value for next review remains at 10,000 amps. However, during the next short-circuit review, the Fault current has increased to 11,500 (15% change); therefore, a review of the Protection System settings is required, and a new baseline of 11,500 amps would be established.

- (Option 2) A time interval, not to exceed six calendar years, or

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

- (Option 3) A combination of the above.

  As a third option, an entity has the flexibilityto apply a combination of the two methodologies based on criteria such as voltage level or Protection System applications. For example, an entity may choose the periodic Protection System review (option 2) and review its Facilities operated above 300 kV on a six year interval, while choosing to use the Fault current review (option 1) for its Facilities operated below 300 kV and periodically compare available Fault currents against the Fault current baseline.

Part 1.4 A quality review of the Protection System settings prior to implementation.

A quality review of the Protection System settings prior to implementation 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 that the developed settings meet the entity's specific requirements for Protection System performance. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of quality reviews.

Part 1.5 For new or revised Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, (Transmission Owners, Generator Owners, and Distribution Providers), procedures to:

Part 1.5 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. Communications among these entities is essential so potential coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

> **1.5.1** Communicate the proposed Protection System settings with the other functional entities.

Part 1.5.1 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.

> **1.5.2** Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified.

Part 1.5.2 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 ensures that the proposed settings are reviewed and the initiating entity receives a response. The response must include any identified coordination issues, or affirm that no issues were identified.

> **1.5.3** Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation.

Part 1.5.3 mandates the entity have a procedure to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures any potential impact to BES reliability are minimized.

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, therefore, 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.

Requirement R2:

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall implement the process established in accordance with Requirement R1.

This requirement directs the applicable entities to implement the process established in Requirement R1. Implementing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, minimizes the possibility of introducing errors, and maximizes the likelihood of maintaining a coordinated Protection System.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.