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~~Faults, such that the Protection ~~System components~~Systems 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
Draft 6 of PRC-027-1 posted for formal comment with ballot	July 29 – September 11, 2015

Anticipated Actions	Date
10-day final ballot	~~June~~October, 2015
NERC Board of Trustees (BOT) adoption	~~August~~November, 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 Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Protection System Issues Addressed by Other ~~Projects~~Reliability Standards:

Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. ~~Other~~Including aspects of protection coordination other than Fault coordination would cause duplication or conflict with the requirements of other Reliability Standards. Specifically, 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~~Reliability Standards:

- 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~~Systems for Performance During Faults**

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

3. **Purpose:** To maintain the coordination of Protection Systems installed ~~for the purpose of detecting~~to detect and isolate Faults on Bulk Electric System (BES ~~Elements and isolating those faulted~~) Elements, such that ~~the~~those 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:**

   4.2. Protection Systems installed ~~for the purpose of detecting~~to detect and isolate Faults on BES Elements ~~and isolating those faulted Elements~~.

   ~~5.~~ **Effective Date:**

5. See the 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 isolating faulted equipment, thus reducing the risk of ~~power system~~BES instability or Cascading ~~by isolating the faulted equipment in a timely manner –~~, and leaving the remainder of the ~~System~~BES operational and more capable of withstanding the next ~~contingency~~Contingency. When Faults occur, properly coordinated ~~protection systems~~ Protection Systems minimize the number of ~~power system~~BES Elements that are 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~~Faults, such that the Protection Systems operate in the intended sequence during Faults~~.~~." Requirement R1 captures this intent by ~~mandating an entity~~ requiring responsible entities establish a process that, when followed, ~~will facilitate consistent results~~allows for their Protection Systems to operate in the

intended sequence during Faults. Requirement R1, Parts 1.1 through 1.3 are key elements to the process for developing ~~settings for its BES Protection Systems. The drafting team contends the parts listed below are essential elements of the coordination process~~Protection System settings.

Part 1.1 Reviewing and updating the ~~information required to coordinate Protection Systems maximizes the likelihood that the process of reviewing and developing~~ short-circuit models used to develop new or revised Protection System settings ~~is completed~~ helps to assure that settings are developed 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~~A review of the ~~affected~~developed 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~~reduces the likelihood of introducing human error ~~into the development of Protection System settings and helps to ensure the~~ and verifies that the settings produced meet the ~~entity's design specifications for Protection System performance.~~technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures~~,~~ are all examples of ~~quality~~ reviews.

Part 1.~~5~~3 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~~essential to the reliability of the BES. ~~Communications~~Communication and review of proposed settings among these entities ~~is essential so~~are necessary to identify potential coordination issues ~~can be identified~~ and ~~addressed~~address the issues prior to implementation of any proposed Protection System changes.

Unforeseen circumstances could require immediate changes to Protection System settings. Requirement R1, Part 1.3.4 requires owners to include a procedure to communicate those unplanned settings changes after-the-fact to the other owner(s) of the electrically-joined Facilities.

Note: In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process ~~to develop~~for developing new and revised Protection System settings for ~~its~~ BES Elements, such that the 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 of short-circuit models for the ~~information required to develop new or revised~~BES Elements under study.

~~1.1.~~1.2. A review of the developed Protection System settings.

~~1.2. A review of~~For 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.~~

~~1.5.~~1.3. ~~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~~provisions to:

~~1.5.1.~~1.3.1. ~~Communicate~~Provide the proposed Protection System settings ~~with the other functional entities~~to the owner(s) of the electrically-joined Facilities.

~~1.5.2.~~1.3.2. ~~Review~~ Respond to any owner(s) that provided its proposed Protection System settings ~~provided by other functional entities, and respond regarding the proposed settings. The response should identify~~pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or ~~affirm~~affirming that no coordination issue(s) were identified.

~~1.5.3.~~1.3.3. Verify that ~~any~~ identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

1.3.4. Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:

1.3.4.1. Implementation or commissioning.

1.3.4.2. Misoperation investigations.

1.3.4.3. Maintenance activities.

1.3.4.4. Emergency replacements required as a result of Protection System component failure.

~~[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.~~

M1. Acceptable evidence ~~includes~~may include, but is not limited to, dated electronic or ~~physical dated records~~hard copy documentation 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.~~Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities (Transmission Owners, Generator Owners, and Distribution Providers) to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. The numerical identifiers in Attachment A represent general protective device functions per ANSI/IEEE *Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Requirement R2 provides responsible entities with options to assess the state of their Protection System coordination.

Option 1 is a time-based methodology. The entity may choose to perform, at least once every six years, a Protection System Coordination Study for each of its BES Protection Systems identified as being affected by changes in Fault current. The six calendar year time interval was selected as a balance between the resources required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

Option 2 is a Fault current based methodology. If Option 2 is initially selected, Fault current baseline(s) must be established prior to the effective date of this Reliability Standard. A baseline may be established when a new Element is installed or after a Protection System Coordination Study has been performed. The baseline(s) will be used as control point(s) for future Fault current comparisons. The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators. At least once every six calendar years following the effective date of this standard, the entity will perform a Protection System Coordination Study when its Fault current comparison identifies a 15 percent or greater deviation in Fault current values (either three-phase or phase-to-ground) at each bus to which the Element is connected. The baseline Fault current value(s) will be re-established whenever a new Protection System Coordination Study is performed. Fault current changes on the System not directly associated with BES modifications are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection System functions (identified in Attachment A of this standard) during Fault conditions. A Fault current deviation threshold of 15 percent or greater (as compared to the established baseline) and a maximum time interval of six calendar years were chosen for these evaluations. These parameters provide an entity with latitude to choose a Fault current threshold and time interval that best match its protection philosophy, Protection System maintenance schedule, or other business considerations, without creating risk to reliability (See the Supplemental Material section for more detailed discussion).

The footnote in Option 2 describes how an entity may change from a time-based option to a Fault current based option for existing Elements when performing Protection System Coordination Studies. The footnote also allows for the creation of a baseline when a Protection System Coordination Study is performed for installing new Elements.

Option 3 provides the entity the choice of using both the time-based and Fault current based methodologies. For example, the entity may choose to utilize the time-based methodology for Protection Systems at more critical Facilities and use the Fault current based methodology for Protection Systems at other Facilities.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall ~~implement the process established in accordance~~, for each BES Element with ~~Requirement R1.~~Protection System functions identified in Attachment A: *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: ~~Operations~~Long-term Planning]*

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years;[2] or,
- Option 3: A combination of the above.

M2. Acceptable evidence ~~includes~~may include, but is not limited to, dated electronic or ~~physical dated records~~hard copy documentation to demonstrate that the responsible entity ~~implemented the process established in~~ performed Protection System Coordination Study(ies) and/or Fault current comparisons in accordance with Requirement R2.

[2] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline by performing a Protection System Coordination Study.

Rationale for Requirement R3:

Utilizing the processes established in Requirement R1 to develop new and revised Protection System settings provides a consistent approach to the development of Protection System settings and will minimize the potential for errors.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~M2.~~M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity utilized its settings development process established in Requirement R1, as specified in Requirement R3.

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 R3, and Measures M1, M2, and ~~M2,~~M3 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 Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include ~~one~~Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include ~~two or more Parts~~Requirement R1, Part 1.3. OR The responsible entity failed to establish ~~a~~any process in accordance with Requirement R1.
R2.	~~N/A~~The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	~~N/A~~The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity ~~implemented the process established~~performed a Protection System Coordination Study for each BES Element, in accordance with Requirement ~~R1~~R2, Option 1, Option 2, or Option 3, but ~~failed~~was late by more than 60 calendar days but less than or equal	The responsible entity ~~implemented the process established~~performed a Protection System Coordination Study for each BES Element, in accordance with Requirement ~~R1~~R2, Option 1, Option 2, or Option 3, but ~~failed to implement two or~~ was late by more ~~Parts~~than 90 calendar days.

			to ~~implement one Part~~90 calendar days.	OR The responsible entity failed to ~~implement the process established~~perform Option 1, Option 2, or Option 3, in accordance with Requirement ~~R1~~R2.
R3.	N/A	N/A	N/A	The responsible entity failed to utilize 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~~—~~, December 7, 2006, "Assessment of Standard PRC-001-0 – System Protection Coordination ~~(December 7, 2006)~~."

NERC System Protection and Control Task Force~~—~~, September 2006, "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~~New standard developed under Project 2007-06

Attachment A

The following Protection System functions[3] are applicable to Requirement R2 if available Fault current levels are used to develop the settings for those Protection System functions:

21 – Distance if:

- infeed is used in determining reach (phase and ground distance), or
- zero-sequence mutual coupling is used in determining reach (ground distance).

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent

67 – AC directional overcurrent if used in a non-communication-aided protection scheme

Notes:

1. The above Protection System functions are susceptible to changes in the magnitude of available short-circuit Fault current. These functions utilize current in their measurement to initiate tripping of circuit breakers. The functions listed above are included in a Protection System Coordination Study because they require coordination with other Protection Systems.
2. See the PRC-027-1 Supplemental Material section for additional information.

[3] ANSI/IEEE Standard C37.2 *Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.*

Purpose~~:~~

The Purpose states: To maintain the coordination of Protection Systems installed ~~for the purpose of detecting~~to detect and isolate Faults on Bulk Electric System (BES~~ Elements and isolating those faulted~~) Elements, such that ~~the~~those Protection Systems operate in the intended sequence during Faults.

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

Applicability

Transmission Owners, Generator Owners, and Distribution Providers are included in the Applicability of PRC-027-1 because they may own Protection Systems that are installed for the purpose of detecting Faults on the Bulk Electric System (BES). It is only those Protection Systems that are under the purview of this standard.

Transmission Owners are included in the Applicability of PRC-027-1 because they own the largest number of Protection Systems installed for the purpose of detecting Faults on the BES.

Generator Owners have Protection Systems installed for the purpose of detecting Faults on the BES. It is important that those Protection Systems are coordinated with Protection Systems owned by Transmission Owners to ensure that generation Facilities do not become disconnected from the BES unnecessarily. Functions such as impedance reaches, overcurrent pickups, and time delays need to be evaluated for coordination.

A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.

After the Protection Systems of Distribution Providers and Generator Owners are shown to be coordinated with other Protection Systems on the BES, there will be little future impact on the entities unless there are significant changes at or near the bus that interconnects with the Transmission Owner. The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current availability upon request by the Distribution Provider or Generator Owner. The Distribution Provider and Generator Owner will determine whether a change in Fault current from the baseline has occurred such that a review of coordination is necessary.

Requirement R1~~:~~

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

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

~~In developing this Standard, the System Protection Coordination Standard Drafting Team (SPCSDT) referenced~~This standard references various publications that discuss protective relaying theory and application. The ~~following~~ description of "coordination of protection" is from the ~~pending revision of~~ IEEE Standard C37.113~~,~~-1999 (Reaffirmed: 2004), *Guide for Protective Relay Applications to Transmission Lines*, which reads:

> *"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~~Entities may have differing technical criteria for the development of Protection System settings based on their own ~~internal tolerances.~~philosophies. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge~~. As~~; as such, a single definition or ~~criteria~~criterion for ~~'~~"Protection System ~~coordination'~~coordination" is not practical.

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

Part 1.1 A ~~method to~~ review and update of short-circuit models for the ~~information required to develop new or revised Protection System settings~~BES Elements under study.

~~Two important studies~~The study used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers ~~are~~is the short ~~-~~circuit study. Including a review and ~~protective device coordination studies. Having a method~~, if necessary, an update of ~~reviewing and updating~~short-circuit study information ~~to make sure it is correct in short circuit studies and protective device coordination studies~~ is necessary to ~~guarantee~~ensure that ~~these two studies~~ information accurately ~~reflect~~reflects the physical power system ~~being considered in~~that will form the basis of the Protection System Coordination Study and development of Protection System relay settings. The results of ~~the studies~~a short-circuit study are only as accurate as the information that ~~their~~its 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~~Because the results of ~~a~~ short~~-~~-circuit ~~study~~studies are used as the basis for protective device coordination studies~~. Because a~~, the short~~-~~-circuit ~~study~~model should~~, as~~ accurately ~~as possible, model the actual network it is representing in order to calculate true Fault currents, the method of~~reflect the ~~review and update of information for the short circuit study might include the following:~~physical power system.

Reviews could include:

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~~System, or how the ~~system~~System will be configured when the proposed relay settings are installed.
3. A review, where applicable, of interconnected Transmission Owner, Generator Owner, ~~or~~and Distribution ~~Provider's~~Provider 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.~~ **Part 1.2** A review of ~~current and voltage transformer ratios,~~the developed 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 introducing human error~~ being introduced into the development of the Protection System settings. A quality review~~ . A review is any systematic process of verifying ~~that~~ the developed settings meet the ~~entity's specific requirements for Protection System performance. Peer~~technical criteria of the entity. Examples of reviews include peer reviews, automated checking programs, and entity-developed review procedures~~ are all examples of quality reviews~~.

Part 1.~~5~~3 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~~provisions to:

Requirement R1, Part 1.~~5~~3 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. ~~Communications~~Communication among these entities is essential so potential Protection System coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

Part 1.~~5~~3.1 ~~Communicate~~1.3.1. Provide the proposed Protection System settings ~~with~~to the ~~other functional entities~~owners of the electrically-joined Facilities.

Requirement R1, Part 1.~~5~~3.1 ~~mandates entities have~~requires the entity to include in its process a ~~procedure~~provision to ~~communicate~~provide proposed Protection System settings ~~with~~to other entities. ~~These communications ensure~~This communication ensures that the other entities have the necessary information to review the settings and determine if there are any Protection System coordination issues.

Part 1.~~5~~3.2 ~~Review proposed Protection System settings~~ Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by ~~other functional entities, and respond regarding the proposed settings. The response should identify~~identifying any coordination issue(s) or ~~affirm~~affirming that no coordination issue(s) were identified.

Requirement R1, Part 1.~~5~~3.2 ~~mandates~~requires the entity receiving proposed Protection System settings ~~have~~to include in its process a ~~procedure to review the settings and~~provision to respond to the entity that initiated the proposed changes. This ensures that the proposed settings are reviewed and that the initiating entity receives a response~~. The response must include any identified~~ indicating Protection System coordination issues were identified, or ~~affirm~~affirmation that no issues were identified.

Part 1.~~5~~3.3 Verify that ~~any~~ identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Requirement R1, Part 1.~~5.~~3~~ mandates~~.3 requires the entity ~~have~~to include in their process a ~~procedure~~provision to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures that any potential impact to BES reliability ~~are~~is minimized.

~~The drafting team recognizes there~~Note: 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~~not to mitigate all of the issues based on engineering judgement. 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~~Further, there ~~are~~could be situations where ~~entities'~~ protection philosophies differ between entities, but ~~they~~the entities can agree that ~~there were no identified~~these differences do not create coordination issues.

Part 1.3.4 Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:

1.3.4.1. Implementation or commissioning.

1.3.4.2. Misoperation investigations.

1.3.4.3. Maintenance activities.

1.3.4.4. Emergency replacements required as a result of Protection System component failure.

Requirement R1, Part 1.3.4 requires the entity to communicate revisions to Protection System settings that occur due to unforeseen circumstances and differ from those developed during the planning stages of projects.

Requirement R2~~:~~

~~The~~This requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall ~~implement the process~~, for each BES Element with Protection System functions identified in Attachment A:

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or
- Option 2: Compare present Fault current values to an established ~~in accordance with Requirement R1.~~Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years;[4] or,
- ~~This requirement directs~~Option 3: A combination of the ~~applicable~~above.

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. Two triggers were established for initiating a review of existing Protection System settings to allow for industry flexibility.

In the first option, an entity may choose a time-based methodology to review Protection System settings, thus eliminating the necessity of establishing a Fault current baseline and periodically performing Fault current comparisons. This option provides the entity the flexibility to choose an interval of up to six calendar years for performing the Protection System Coordination Studies for those Protection System functions in Attachment A. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The second option allows the entity to periodically check for 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 each bus to which an Element is connected. This option allows the entity to choose an interval of up to six calendar years to perform the Fault current comparisons

[4] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline by performing a Protection System Coordination Study.

and Protection System Coordination Studies. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. A maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) was established based on generally-accepted margins for setting Protection Systems in which incremental Fault current changes would not interfere with coordination. The 15 percent maximum deviation provides an entity with latitude to choose a Fault current threshold that best matches its protection philosophy, or other business considerations. The Fault current based option requires an entity to first establish a Fault current baseline to be used as a point of reference 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 all generation in service and all transmission BES Elements in their normal operating state.

An entity that elects to use Option 2 following the effective date of the standard, must establish its baseline prior to the effective date. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline upon performing a Protection System Coordination Study. The Fault current values used in the original baseline can be updated or created when a Protection System Coordination Study is performed. The baseline values at each bus to which an Element is connected are updated whenever a new Protection System Coordination Study is performed for the subject Protection System.

> **Example:** ~~implement the~~ An initial 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 percent change); consequently, no Protection System Coordination Study is required since the increase is below the maximum 15 percent deviation. The baseline value for the next study remains at 10,000 amps because no study was performed. However, during the next Fault current comparison, the Fault current has increased to 11,500 (15 percent change); therefore, a Protection System Coordination Study is required, and a new baseline of 11,500 amps would be established.
>
> **Note:** In the first review described above, if the entity decides to perform a Protection System Coordination Study at the 12.5 percent deviation and the results of the study indicate that the settings still meet the setting criteria of the entity, then no settings changes are required and the baseline Fault current(s) would be updated.

As a third option, an entity has the flexibility to apply a combination of the two methodologies. For example, an entity may choose the periodic Protection System review (Option 1) and review its Facilities operated above 300 kV on a six year interval, while choosing to use the Fault current comparison (Option 2) for its Facilities operated below 300 kV.

Attachment A identifies the Protection System functions susceptible to changes in the magnitude of available short-circuit Fault current. These functions utilize AC current in their measurement to initiate tripping of circuit breakers. The numerical identifiers in Attachment A represent general device functions according to *ANSI/IEEE Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*. The device functions listed in Attachment A are to be reviewed provided they require coordination with other Protection Systems. The following scenarios provide some examples for applying Attachment A.

A “51 – AC inverse time overcurrent” relay connected to a CT on the neutral of a generator step-up transformer, referred to as “51N – AC Inverse Time Earth Overcurrent Relay (Neutral CT Method)” in ANSI/IEEE Standard C37.2, would be included in a Protection System Coordination Study. Also applicable, are “51 – AC Inverse time overcurrent” relays connected to CTs on the phases of an autotransformer for through-fault protection. Overcurrent functions used in conjunction with other functions are to be reviewed as well. An example is a definite-time overcurrent function, which is a “50 – Instantaneous overcurrent” function used in conjunction with a “62 – Time-delay” function.

If the functions listed in Attachment A are used in conjunction with other functions, they would be included in a Protection System Coordination Study provided they require coordination with other Protection Systems. An example of this is a time-delayed “21 – Distance” function, which is a “21 – Distance” function with a “62 – Time-delay” function. Another example would be a definite-time overcurrent function, which is a “50 – Instantaneous overcurrent” function with a “62 – Time-delay” function. A “50 – Instantaneous overcurrent” function used for supervising a “21 – Distance” function would not be included in a Protection System Coordination Study as it does not require coordination with other Protection Systems.

Reviewing “21 – Distance” functions is limited to those applied for phase and ground distance where infeed is used in determining the phase or ground distance setting when zero-sequence mutual coupling is used in determining the setting. Where infeed is not used in determining the setting, “21 – Distance” functions would not be included in a Protection System Coordination Study, as the reach is not susceptible to changes in the magnitude of available short-circuit Fault current. Where infeed is used in determining the reach, coordination can be affected by changes in the magnitude of available short-circuit Fault current. Two examples where infeed may be used in determining the reach, are protection for a transmission line with a long tap and a three-terminal transmission line. Ground distance functions are influenced by zero-sequence mutual coupling. The ground distance measurement can appear to be greater than or less than the true distance to a Fault when there is zero-sequence mutual coupling. The influence of zero-sequence mutual coupling changes with the magnitude of available short-circuit current. Therefore, “21 – Distance” functions would be included in a Protection System Coordination Study, when zero-sequence mutual coupling is used in determining the setting.

Requirement R3

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1~~. Implementing~~ to develop new and revised Protection System settings for BES Elements.

The reliability objective of this requirement is for applicable entities to utilize the process established in Requirement R1. Utilizing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, ~~minimizes~~decreases the possibility of introducing errors, and ~~maximizes~~increases 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~~will be moved to this section.