Exhibit A

Proposed Reliability Standards and Definitions

Exhibit A-1

Proposed Reliability Standard PRC-027-1

A. Introduction

1. **Title:** **Coordination of Protection Systems for Performance During Faults**
2. **Number:** PRC-027-1
3. **Purpose:** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that 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: Protection Systems installed to detect and isolate Faults on BES Elements.
5. **Effective Date:** See the Implementation Plan for PRC-027-1, Project 2007-06 System Protection Coordination.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A review and update of short-circuit model data for the BES Elements under study.

1.2. A review of the developed Protection System settings.

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

1.3.1. Provide the proposed Protection System settings to the owner(s) of the electrically joined Facilities.

1.3.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

1.3.3. Verify that 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 implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity established a process to develop settings for its Protection Systems, in accordance with Requirement R1.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A: *[Violation Risk Factor: Medium] [Time Horizon: 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 BES Element is connected, all in a time interval not to exceed six-calendar years;[1] or,
- Option 3: Use a combination of the above.

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

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]*

[1] 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. The Fault current baseline for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA). 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 BES Element, the entity may establish the baseline by performing a Protection System Coordination Study.

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 shall each keep data or evidence to show compliance with Requirements R1, R2, and R3, and Measures M1, M2, and 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 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	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 Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.3. OR The responsible entity failed to establish any process in accordance with Requirement R1.
R2.	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.	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 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 60 calendar days but less than or equal to 90 calendar days.	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 90 calendar days. OR The responsible entity failed to perform Option 1, Option

				2, or Option 3, in accordance with Requirement 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 – "Power Plant and Transmission System Protection Coordination."

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

NERC System Protection and Control Task Force, September 2006, "The Complexity of Protecting Three-Terminal Transmission Lines."

Version History

Version	Date	Action	Change Tracking
1	November 5, 2015	Adopted by NERC Board of Trustees	New standard developed under Project 2007-06

Attachment A

The following Protection System functions[2] are applicable to Requirement R2 if: (1) available Fault current levels are used to develop the settings for those Protection System functions; and (2) those Protection System functions require coordination with other Protection Systems.

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 utilize current in their measurement to initiate tripping of circuit breakers. Changes in the magnitude of available Fault current can impact the coordination of these functions.
2. See the PRC-027-1 Supplemental Material section for additional information.

[2] 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 to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.

Coordinated Protection Systems enhance reliability by isolating faulted equipment, reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. This standard requires that entities establish and implement a process to coordinate their 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 data 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 for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults.

The reliability objective of this requirement is to have applicable entities establish a process to develop settings for coordinating their Protection Systems, such that they operate in the intended sequence during Faults. The parts that are included as elements of the process 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 settings.

This standard references various publications that discuss protective relaying theory and application. The 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."*

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

The coordination of some Protection Systems may seem unnecessary, such as for a line that is protected solely by dual current differential relays. However, backup Protection Systems that are enabled to operate based on current or apparent impedance with some definite or inverse time delay must be coordinated with other Protection Systems of the BES Element such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A review and update of short-circuit model data for the BES Elements under study.

The short-circuit study provides the necessary Fault currents used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers. Generator Owners and Distribution Providers may not have or maintain short-circuit models; consequently, these entities would obtain the short-circuit model data from the Transmission Planners, Planning Coordinators, or Transmission Owners. Including a review and, if necessary, an update of short-circuit study information is necessary to ensure that information accurately reflects the physical power system that will form the basis of the Protection System Coordination Study and development of Protection System relay settings. The results of a short-circuit study are only as accurate as the information that 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. Because the results of short-circuit studies are used as the basis for protective device coordination studies, the short-circuit model should accurately reflect the physical power system.

Reviews could include:

1. A review of applicable BES line, transformer, and generator impedances and Fault currents.

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, where applicable, of interconnected Transmission Owner, Generator Owner, and Distribution Provider information.

Part 1.2 A review of the developed Protection System settings.

A review of the Protection System settings prior to implementation reduces the possibility of introducing human error. A review is any systematic process of verifying the developed settings meet the technical criteria of the entity. Examples of reviews include peer reviews, automated checking programs, and entity-developed review procedures.

Part 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

Requirement R1, Part 1.3 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. 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 1.3.1 1.3.1. Provide the proposed Protection System settings to the owners of the electrically joined Facilities.

Requirement R1, Part 1.3.1 requires the entity to include in its process a provision to provide proposed Protection System settings to other entities. 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 1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

Requirement R1, Part 1.3.2 requires the entity receiving proposed Protection System settings to include in its process a 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 indicating Protection System coordination issues were identified, or affirmation that no issues were identified.

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

Requirement R1, Part 1.3.3 requires the entity to include in their process a 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 is minimized.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

Note: There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judgment. 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. Further, there could be situations where protection philosophies differ between entities, but the entities can agree that 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 implementation or commissioning, Misoperation investigations, maintenance activities, or 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

This requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall, 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 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 BES Element is connected, all in a time interval not to exceed six-calendar years;[3] or,

[3] 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. The Fault current baseline for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA). 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 BES Element, the entity may establish the baseline by performing a Protection System Coordination Study.

- Option 3: Use a combination of the 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 a BES Element is connected. Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators, or Transmission Owners. This option allows the entity to choose an interval of up to six-calendar years to perform the Fault current comparisons 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.

As described in the footnote for Requirement R2, Option 2, an entity that elects to initially use Option 2 must establish its baseline prior to the effective date of the standard. 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 BES Element, the entity may establish the baseline upon performing a Protection System Coordination Study. The Fault current baseline values can be updated or established when a Protection System Coordination Study is performed. The baseline values at each bus to which a BES Element is connected are updated whenever a new Protection System Coordination Study is performed for the subject

Protection System. The footnote also states that the Fault current baselines may be established for BES generating resources at the generator, the BES aggregation point for dispersed power producing resources, or at the common point of connection at 100 kV or above.

> **Example:** Prior to the effective date of PRC-027-1, an entity intending to use Option 2 of Requirement R2 establishes an initial baseline; e.g., 10,000 amps at the bus to which the BES Element under study is connected. A short-circuit review performed on March 1, 2024, for example, identifies that the Fault current has increased to 11,250 amps (12.5 percent deviation); consequently, no Protection System Coordination Study is required since the increase is below the maximum 15 percent deviation. The baseline value for the next comparison (to be performed no later than December 31, 2030) remains at 10,000 amps because no study was required as a result of the initial comparison. During the next six-year interval, Fault current comparison identifies that the Fault current has increased to 11,500 (15 percent deviation); therefore, a Protection System Coordination Study is required (and must also be completed no later than December 31, 2030), 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-calendar-year interval, while choosing to use the Fault current comparison (Option 2) for its Facilities operated below 300 kV.

The Protection System functions listed in Attachment A utilize AC current in their measurement to initiate tripping of circuit breakers and the coordination of these functions is susceptible to changes in the magnitude of available short-circuit Fault current. These functions are included in Attachment A based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. Examples of functions not included in Attachment A because they do not meet both of the criteria are differential relays and Fault detectors. 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 following provide additional information regarding the Protection System functions in 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.

The 67 – AC directional overcurrent function utilized in Protection Systems for Transmission lines can be instantaneous overcurrent, inverse time overcurrent, or both instantaneous overcurrent and inverse time overcurrent. For example, in a communication-aided directional comparison blocking (DCB) scheme, the instantaneous overcurrent function is set very sensitive. When a single line-to-ground Fault occurs on a Transmission line, the Fault is detected by a number of Protection Systems for other Transmission lines. Signals from communication equipment are transmitted and received to block the other Protection Systems for the non-faulted Transmission lines from operating, thereby providing the coordination. A 67 – AC directional overcurrent function used in a permissive overreaching transfer trip scheme (POTT) relies on a signal from the remote end to operate and, therefore, does not require coordination with other Protection Systems.

Instantaneous overcurrent and/or inverse time overcurrent for a 67 – AC directional overcurrent function are utilized in a non-communication-aided Protection System for Transmission lines. As communication is not used to prevent operation for Faults outside a Protection System’s zone of protection, coordination is necessary with other Protection Systems for buses, transformers, and other Transmission lines. The instantaneous overcurrent function should be set to not overreach the end of the Transmission line. The inverse time overcurrent function should be set to coordinate with the inverse time overcurrent function of other Protection Systems. Changes in the magnitude of available Fault current can affect the coordination.

Requirement R3

The requirement states: 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.

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, decreases the possibility of introducing errors, and 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 will be moved to this section.

Rationale for Requirement R1:

Coordinated Protection Systems enhance reliability by isolating faulted equipment, thus reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. The stated purpose of this standard is: "To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults." Requirement R1 captures this intent by requiring responsible entities establish a process that, when followed, 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 Protection System settings.

Part 1.1 Reviewing and updating the short-circuit model data used to develop new or revised Protection System settings helps to assure that settings are developed using accurate, up-to-date information. Generator Owners and Distribution Providers may not have or maintain short-circuit models; consequently, these entities would obtain the short-circuit model data from the Transmission Planners, Planning Coordinators, or Transmission Owners.

Part 1.2 A review of the developed Protection System settings reduces the likelihood of introducing human error and verifies that the settings produced meet the technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of reviews.

Part 1.3 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 essential to the reliability of the BES. Communication and review of proposed settings among these entities are necessary to identify potential coordination issues and address the issues prior to implementation of any proposed Protection System changes.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

Unforeseen circumstances could require immediate changes to Protection System settings. Requirement R1, Part 1.3.4 requires owners to include provisions 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.

Rationale for Requirement R2:

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 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 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-calendar years, a Protection System Coordination Study for each of its Protection Systems identified in Attachment A. 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 BES 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, Planning Coordinators, or Transmission Owners. In a time interval not to exceed six-calendar years following the effective date of this standard, an entity must perform a Fault current comparison. If the comparison identifies a deviation less than 15 percent, no further action is required for that six-year interval; however, if the 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 BES Element is connected, the entity must also perform a Protection System Coordination Study during the same six-year interval. 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 BES Elements as well as establishing baselines for new BES Elements by performing Protection System Coordination Studies. The footnote also states that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA).

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.

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.

Exhibit A-2

Proposed Reliability Standard PER-006-1

A. Introduction

1. **Title:** **Specific Training for Personnel**
2. **Number:** **PER-006-1**
3. **Purpose:** To ensure that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the Bulk Electric System.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Operator that has:

   4.1.1.1. Plant personnel who are responsible for the Real-time control of a generator and receive Operating Instruction(s) from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center.

5. **Effective Date:** See Implementation Plan for Project 2007-06.2.

B. Requirements and Measures

R1. Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies) it operates. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M1. Each Generator Operator shall have available for inspection, evidence that the applicable personnel completed training. This evidence may be documents such as training records showing successful completion of training that includes training materials, the name of the person, and date of training.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority:

   "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   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 Generator Operator shall keep data or evidence of Requirement R1 for the current year and three previous calendar years.

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.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • one applicable personnel at a single Facility, or • 5% or less of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • two applicable personnel at a single Facility, or • more than 5% and less than or equal to 10% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • three applicable personnel at a single Facility, or • more than 10% and less than or equal to 15% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • five or more applicable personnel at a single Facility, or • more than 15% of the total applicable personnel of the Generator Operator. **OR** The Generator Operator failed to provide training as described in Requirement R1 to its applicable personnel.

D. Regional Variances

None.

E. Associated Documents

Project 2007-06.2 Implementation Plan[1]

[1] http://www.nerc.com/pa/Stand/Project200706_2SystemProtectionCoordinationDL/Project_2007_06_2_Imp_Plan_Draft_1_2016_03_10_Clean.pdf

Version History

Version	Date	Action	Change Tracking
1	August 11, 2016	Adopted by the NERC Board of Trustees	New standard developed under Project 2007-06.2

Guidelines and Technical Basis

Requirement R1

The Generator Operator (GOP) monitors and controls its generating Facilities in Real-time to maintain reliability. To accomplish this, applicable plant personnel responsible for Real-time control of a generating Facility must be trained on how the operational functionality of Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility. Although, training does not have to be Facility-specific, the standard applies to plant operating personnel associated with the specific Facility to which they have Real-time control. This does not include plant personnel not responsible for Real-time control (e.g., fuel or coal handlers, electricians, machinists, or maintenance staff).

A periodicity for training is not specified in Requirement R1 because the GOP must ensure its plant personnel who have Real-time control of a generator are trained. The Generator Operator must also ensure it provides applicable training that results from changes to the operational functionality of the Protection Systems and Remedial Action Schemes that affect the output of the generation Facility(ies).

The phrase "operational functionality" focuses the training on how Protection Systems operate and prevent possible damage to Elements. It also addresses how RAS detects pre-determined BES conditions and automatically takes corrective actions.

Considerations for operational functionality may include, but are not limited to the following:

- Purpose of protective relays and RAS
- Zones of protection
- Protection communication systems (e.g., line current differential, direct transfer trip, etc.)
- Voltage and current inputs
- Station dc supply associated with protective functions
- Resulting actions – tripping/closing of breakers; tripping of a generator step-up (GSU) transformer; or generator ramping/tripping control functions

Requirement R1 focuses on the operational functionality of Protection Systems and Remedial Action Schemes specific to the generating plant and not the Bulk Electric System.

This requirement focuses on those systems that are related to the electrical output of the generator. Protective systems which trip breakers serving station auxiliary loads (e.g., such as pumps, fans, or fuel handling equipment) are not included in the scope of this training. Furthermore, protection of secondary unit substation (SUS) or low voltage switchgear transformers and relays protecting other downstream plant electrical distribution system components are not in the scope of this training, even if a trip of these devices might eventually result in a trip of the generating unit.

Rationale

Rationale for Requirement R1: Protection Systems and Remedial Action Schemes (RAS) are an integral part of reliable Bulk Electric System (BES) operation. This requirement addresses the reliability objective of ensuring that Generator Operator (GOP) plant operating personnel understand the operational functionality of Protection Systems and RAS and their effects on generating Facilities.

Exhibit A-3

Proposed Definitions

Clean Version of Proposed Definitions

Proposed Definitions

Project 2007-06 System Protection Coordination
Project 2007-06.2 Phase 2 of System Protection Coordination

Proposed Definitions

This section includes the three proposed new or modified definitions that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval, in accordance with the associated implementation plan.

New or Modified Term(s) for Glossary of Terms Used in NERC Reliability Standards

Protection System Coordination Study

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

Operational Planning Analysis (OPA)

An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts; generation output levels; Interchange; known Protection System and Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Real-time Assessment (RTA)

An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load; generation output levels; known Protection System and Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Interchange; Facility Ratings; and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Redline Version of Proposed Definitions

Proposed Definitions

Project 2007-06 System Protection Coordination
Project 2007-06.2 Phase 2 of System Protection Coordination

Proposed Definitions

This section includes the three proposed new or modified definitions that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval, in accordance with the associated implementation plan.

New or Modified Term(s) for Glossary of Terms Used in NERC Reliability Standards

Protection System Coordination Study

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

Operational Planning Analysis (OPA)

An evaluation of projected system conditions to assess anticipated (pre~~-~~-Contingency) and potential (post~~-~~-Contingency) conditions for next~~-~~-day operations. The evaluation shall reflect applicable inputs including, but not limited to~~,~~: load forecasts; generation output levels; Interchange; known Protection System and ~~Special Protection System~~Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third~~-~~-party services.)

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