

September 12, 2016

VIA ELECTRONIC FILING

Kirsten Walli, Board Secretary
Ontario Energy Board
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Re: *North American Electric Reliability Corporation*

Dear Ms. Walli:

The North American Electric Reliability Corporation hereby submits Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards PRC-027-1 and PER-006-1 and Retirement of PRC-001-1-1(ii). NERC requests, to the extent necessary, a waiver of any applicable filing requirements with respect to this filing.

Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

/s/ Holly A. Hawkins

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Enclosure

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**ONTARIO ENERGY BOARD
OF THE PROVINCE OF ONTARIO**

**NORTH AMERICAN ELECTRIC)
RELIABILITY CORPORATION)**

**PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS PRC-027-1 AND PER-
006-1 AND RETIREMENT OF PRC-001-1.1(ii)**

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September 12, 2016

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**ONTARIO ENERGY BOARD
OF THE PROVINCE OF ONTARIO**

**NORTH AMERICAN ELECTRIC)
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**PETITION OF THE
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FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS PRC-027-1 AND PER-
006-1 AND RETIREMENT OF PRC-001-1.1(ii)**

The North American Electric Reliability Corporation (“NERC”) hereby submits:

- proposed Reliability Standards PRC-027-1 and PER-006-1 (Exhibit A);
- proposed new and revised definitions to be incorporated into the *Glossary of Terms Used in NERC Reliability Standards* (“NERC Glossary”) for the following terms: (1) Protection System Coordination Study; (2) Operational Planning Analysis (“OPA”); and (3) Real-time Assessment (“RTA”) (Exhibit A);
- the retirement of Reliability Standard PRC-001-1.1(ii);
- the associated Implementation Plans (Exhibit B); and
- the associated Violation Risk Factors (“VRFs”) and Violation Severity Levels (“VSLs”) (Exhibit F).¹

This filing presents the technical basis and purpose of the proposed Reliability Standards and NERC Glossary definitions, a summary of the development history (Exhibit G), and a demonstration that the proposed Reliability Standards and definitions meet the Reliability Standards criteria (Exhibit C). The NERC Board of Trustees (“Board”) adopted proposed Reliability Standard PRC-027-1 and the definition of Protection System Coordination Study on November 5, 2015, and proposed Reliability Standard PER-006-1 and the modified definitions of OPA and RTA on August 11, 2016.

¹ Unless otherwise designated, all capitalized terms used herein shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* (“NERC Glossary”), available at http://www.nerc.com/files/Glossary_of_Terms.pdf.

I. EXECUTIVE SUMMARY

The purpose of the proposed Reliability Standards and the proposed NERC Glossary definitions is to: (1) 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; and (2) require registered entities to provide training to their relevant personnel on Protection Systems and Remedial Action Schemes (“RAS”) to help ensure that the BES is reliably operated. The reliable and coordinated operation of Protection Systems is essential to Bulk Power System (“BPS”) reliability for the following reasons. Protection Systems help maintain reliability by isolating faulted equipment, thereby reducing the risk of instability or Cascading, and leaving the remainder of the BPS operational and more capable of withstanding a future Contingency. In the event of a Fault, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. System reliability is reduced or threatened if a Protection System can no longer perform as designed because of a failure of its relays. Further, the functions, settings, and limitations of Protection Systems are recognized and integrated in deriving System Operating Limits (“SOLs”) and Interconnection Reliability Operating Limits (“IROLs”).²

Issues related to the coordination of Protection Systems are currently addressed in Reliability Standard PRC-001-1.1(ii), which includes the following six requirements:

- *Requirement R1* provides that “[e]ach Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.”

² SOLs and IROLs are vital concepts in NERC’s Reliability Standards as they establish acceptable performance criteria both pre- and post-contingency to maintain reliable Bulk Electric System operations.

- *Requirement R2* provides that Generator Operators and Transmission Operators shall notify certain other entities of relay or equipment failures that reduce system reliability and take corrective action as soon as possible.
- *Requirement R3* addresses the coordination of new protective systems and changes to existing protective systems.
- *Requirement R4* provides that Transmission Operators must coordinate Protection Systems on major transmission lines and interconnections with certain neighboring entities.
- *Requirement R5* requires Generator Operators and Transmission Operators to coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others.
- *Requirement R6* requires Transmission Operators and Balancing Authorities to monitor the status of each Special Protection System (“SPS”) in their area and notify affected entities of any change in status.

As explained further below, NERC is proposing to retire Reliability Standard PRC-001-1.1(ii). The Requirements in PRC-001-1.1(ii) are being replaced by proposed Reliability Standards PRC-027-1 and PER-006-1 and the proposed definitions, or are addressed by Reliability Standards developed since the effective date of PRC-001-1, as follows:

PRC-001-1.1(ii) Requirement R1: Along with currently-effective Personnel Performance, Training, and Qualifications (“PER”) Reliability Standards, proposed Reliability Standard PER-006-1 and the proposed modifications to the definitions of OPA and RTA are designed to improve upon and replace PRC-001-1.1(ii), Requirement R1 in addressing the reliability goal of requiring Generator Operators, Balancing Authorities, and Transmission Operations to be “familiar with” the purpose and limitations of Protection System schemes. Focusing on the certification and training requirements in the PER group of Reliability Standards as the mechanism for ensuring that the necessary personnel are familiar with the purpose and limitations of Protection System schemes will provide more precise and auditable requirements to achieve the reliability objective of Requirement R1 of PRC-001-1.1(ii). Currently-effective PER-005-2, Requirement R6 already requires Generator Operators to provide training to their centrally-located dispatch personnel on

how their job functions impact BES reliability. Proposed PER-006-1 adds a requirement in the PER standards that Generator Operators train their plant operating personnel on the operational functionality of Protection Systems and RAS that affect the output of their generating Facilities.³ For Transmission Operators and Balancing Authorities, the reliability goal of Requirement R1 is addressed by the currently-effective certification and training requirements in PER-003-1 and PER-005-2, respectively.

Additionally, the proposed modifications to the definitions of OPA and RTA further the objective of PRC-001-1.1(ii), Requirement R1 by requiring that Transmission Operators, as well as Reliability Coordinators, consider the functions and limitations of Protection Systems and RAS when performing the OPAs and RTAs required under the Transmission Operations (“TOP”) and Interconnection Reliability Operations and Coordination (“IRO”) group of Reliability Standards to determine whether there are any actual or expected SOL or IROL exceedances.

PRC-001-1.1(ii) Requirement R2: The reliability goal of PRC-001-1.1(ii) Requirement R2 for Generator Operators and Transmission Operators to notify certain other entities of certain relay or equipment failures and take corrective action as soon as possible is addressed in recently submitted Reliability Standards IRO-001-4, IRO-008-2, IRO-010-2, TOP-001-3, and TOP-003-3.⁴ As discussed below, these standards collectively require, among others things, that (1) Reliability Coordinators, Balancing Authorities, and Transmission Operators maintain reliability in their area by their own actions or by directing the actions of others (e.g., taking corrective action in event of relay or equipment failure), and (2) require other registered entities to provide

³ The phrase “Protection System schemes” in PRC-001-1.1(ii), Requirement R1 maps to the NERC Glossary terms “Protection Systems” and “Remedial Action Schemes,” as explained below.

⁴ These Reliability Standards – along with IRO-002-4, IRO-014-3, IRO-017-1, and TOP-002-4 – were submitted on March 25, 2015 and were approved by FERC in Order No. 817. *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178, 80 Fed. Reg. 73977 (2015).

Reliability Coordinators and Transmission Operators with data or notifications under certain circumstances, including notifications regarding the status or degradation of Protection Systems and SPS.⁵

PRC-001-1.1(ii) Requirements R3 and R4: Proposed Reliability Standard PRC-027-1 is designed to improve upon and replace Requirements R3 and R4 of PRC-001-1.1(ii) in addressing the reliability objective of Protection System coordination. Proposed Reliability Standard PRC-027-1 provides a clear set of Requirements that obligate applicable entities to (1) implement a process for establishing and coordinating new or revised Protection System settings and (2) periodically study Protection System settings that could be affected by incremental changes in Fault current to ensure they continue to be appropriate (i.e., that the Protection System continues to operate in the intended sequence during Faults).

PRC-001-1.1(ii) Requirement R5: The reliability objective of coordinating changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others is now primarily addressed by Reliability Standard TOP-003-3, as well as Reliability Standards TOP-001-3, TOP-002-4, IRO-008-2, IRO-010-2, and IRO-017-1, which were developed since PRC-001-1.1(ii) went into effect. As discussed further below, these Reliability Standards require coordination and analysis of changes in conditions that would necessitate changes to the Protection Systems of others, amongst other actions.

PRC-001-1.1(ii) Requirement R6: The reliability objective of requiring Transmission Operators and Balancing Authorities to monitor the status of each SPS in their area and notify

⁵ Per FERC's order approving the revised definition of SPS on June 23, 2016, SPS and RAS are interchangeable terms. See *N. Am. Elec. Reliability Corp.*, Docket No. RD16-5-000 (June 23, 2016) (unpublished letter order). This filing uses the NERC Glossary terms "RAS" or "SPS" depending on the language in the Requirement the filing is discussing. If the filing is discussing a Requirement that uses RAS, for instance, the filing will refer to RAS when discussing that Requirement.

affected entities of any change in status is addressed in Reliability Standard TOP-001-3 and TOP-003-3. Requirements R10 and R11 of TOP-001-3 create an affirmative obligation for Transmission Operators and Balancing Authorities to monitor the status of SPS. Pursuant to TOP-003-3, Transmission Operators and Balancing Authorities must provide notifications regarding any change in Protection System status to other Transmission Operators and Balancing Authorities.

In summary, the proposed Reliability Standards represent an improvement over currently-effective PRC-001-1.1(ii) and more effectively accomplish the reliability goals of ensuring that appropriate personnel are trained on Protection Systems and that Protection System settings are appropriately studied, coordinated, and monitored. The proposed Reliability Standards and NERC Glossary definitions, and the proposed retirement of PRC-001-1.1(ii) are just, reasonable, not unduly discriminatory, or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. BACKGROUND

A. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Reliability Standard development process. NERC develops Reliability

Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.⁶ NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders. Further, a vote of stakeholders and adoption by the NERC Board is required before NERC submits the Reliability Standard to the applicable governmental authorities.

B. Development of the Proposed Reliability Standards

As further described in Exhibit G hereto, proposed Reliability Standard PRC-027-1 and the NERC Glossary term Protection System Coordination Study were developed as part of Project 2007-06 – System Protection Coordination to replace and improve upon Requirements R3 and R4 of PRC-001-1.1(ii). On September 11, 2015, the sixth draft of proposed Reliability Standard PRC-027-1 and the definition for the new NERC Glossary term Protection System Coordination Study received the requisite approval from the registered ballot body. A final ballot for the standard and the definition concluded on October 14, 2015, with a ballot body approval of 80.94%. The NERC Board adopted the standard and definition on November 5, 2015.⁷

PER-006-1 and the revisions to the definitions of OPA and RTA were developed in the second phase of that project, Project 2007-06.2 – Phase 2 of System Protection Coordination to

⁶ The NERC Rules of Procedure are available at <http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

⁷ NERC did not immediately file the proposed PRC-027-1 with the applicable governmental authorities following the Board's November 2015 adoption of the standard so as to present to the applicable governmental authorities the retirement of PRC-001-1.1(ii) in its entirety following the adoption of PER-006-1 and the retirement of the remaining requirements in PRC-001-1.1(ii).

replace and improve upon Requirement R1 of PRC-001-1.1(ii). Project 2007-06.2 also addressed the retirement of Requirements R2, R5, and R6 of PRC-001-1.1(ii). Proposed PER-006-1, the revised definitions of OPA and RTA, and the retirement of PRC-001-1.1(ii), Requirements R2, R5, and R6 received the requisite approval from the registered ballot body on April 25, 2016. Final ballots for the standard, the definitions, and the retirements concluded on May 26, 2016, with ballot body approvals of 82.52% (PER-006-1) and 83.37% (OPA and RTA). The NERC Board adopted the proposed standard, definitions, and retirements on August 11, 2016.

IV. JUSTIFICATION FOR APPROVAL

As discussed below and in Exhibit C, the proposed Reliability Standards, NERC Glossary definitions and the retirement of PRC-001-1.1(ii) satisfy the Reliability Standards criteria and are just, reasonable, not unduly discriminatory, or preferential, and in the public interest. As noted above, the purpose of the proposed Reliability Standards and the proposed NERC Glossary definitions is to: (1) maintain the coordination of Protection Systems installed to detect and isolate Faults on BES Elements, such that those Protection Systems operate in the intended sequence during Faults; and (2) require registered entities to provide training to their relevant personnel on Protection Systems and RAS to help ensure that the BES is reliably operated. Reliability Standard PRC-001-1.1(ii) currently addresses issues related to the coordination of Protection Systems. As explained further below, NERC proposes to retire Reliability Standard PRC-001-1.1(ii) as the requirements therein are being replaced by proposed Reliability Standards PRC-027-1 and PER-006-1 and the proposed definitions, or are addressed by Reliability Standards developed since the effective date of PRC-001-1.

The following section is organized as follows:

- 1) A discussion of proposed Reliability Standard PER-006-1, the revisions to the definition of OPA and RTA, and the manner in which they, along with currently-effective

Reliability Standards PER-003-1 and PER-005-2, replace and improve upon Requirement R1 of PRC-001-1.1(ii).

- 2) A discussion of proposed Reliability Standard PRC-027-1, the new NERC Glossary term Protection System Coordination Study, and the manner in which they replace and improve upon Requirements R3 and R4 of PRC-001-1.1(ii).
- 3) A discussion of the manner in which TOP and IRO Reliability Standards replace and improve upon Requirements R2, R5 and R6 of PRC-001-1.1(ii).
- 4) An explanation of the manner in which TOP and IRO Reliability Standards resolve outstanding Federal Energy Regulatory Commission (“FERC”) directives related to PRC-001-1.1(ii).
- 5) A discussion on the enforceability of the proposed Reliability Standards.

A. PER Reliability Standards and Retirement of Requirement R1 of PRC-001-1.1(ii)

Reliability Standard PRC-001-1.1(ii), Requirement R1 provides that “[e]ach Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.” This requirement serves an important reliability objective as Protection Systems and RAS are an integral part of reliable BES operation and must be applied and operated reliably.⁸ As noted above, Protection Systems help maintain reliability by detecting and isolating faulted equipment, thereby limiting the severity and spread of system disturbances, and preventing damage to protected BES Elements. Further, the functions, settings, and limitations of Protection Systems schemes are critical in establishing SOLs and IROLs. In addition, RAS help maintain BES stability, voltages, and power flows, and limit the impact of Cascading or extreme events.

⁸ The phrase “Protection System schemes” in PRC-001-1.1(ii), Requirement R1 maps to both the NERC Glossary terms “Protection Systems” and “Remedial Action Schemes.” As RAS are essentially schemes comprised of Protection Systems, the phrase “Protection System schemes” would include RAS.

When Generator Operator, Transmission Operator, and Balancing Authority personnel understand the purpose and functions of Protection System schemes applied in their area, they can operate the BES in a more reliable manner, as follows:

- When Generator Operator personnel understand the purpose and limitations of Protection System schemes, the Generator Operator better understands how those schemes affect the output of their generation facilities and, in turn, are better equipped to operate their generation facilities to maintain reliability.
- When Transmission Operator personnel are familiar with the purpose and limitations of Protection System schemes in their area, the Transmission Operator has a better understanding of the manner in which their system operates and, in turn, can more effectively operate their system within SOLs and IROLs, and identify when the reliability of the system is threatened or reduced.
- When Balancing Authority personnel are familiar with the purpose and limitations of Protection System schemes in their area, the Balancing Authority has a better understanding of the manner in which these schemes affect the maintenance of generation, load and interchange balance and, in turn, can ensure that Protection Schemes are enabled when needed for reliability.

The language of PRC-001-1.1(ii), Requirement R1, however, has created some uncertainties. First, because the requirement does not specify the type of Generator Operator, Transmission Operator, or Balancing Authority personnel that must be familiar with the purpose and limitations of Protection System schemes, it is unclear to many industry stakeholders which personnel must have the requisite familiarity for the functional entity to satisfy the requirement. There is also uncertainty as to the steps an applicable entity must take to demonstrate that it has the requisite familiarity. For example, applicable entities are uncertain whether the standard requires them to conduct formal training of certain personnel whose job functions relate to or could be affected by Protection System schemes, or whether it is sufficient for the entity to have reference documents discussing the purpose and limitations of Protection System schemes that personnel may review when they deem necessary.

Due to the importance of Protection Systems to the reliable operation of the BPS, the Reliability Standards related to these systems should set clear obligations. To that end, NERC proposes to replace PRC-001-1.1(ii), Requirement R1 with new and existing formal training requirements in the PER group of Reliability Standards. Focusing on formal training requirements will help ensure that the necessary personnel are familiar with and understand the purpose and limitations of Protection System schemes while providing more precise and auditable requirements. The following sections discuss the manner in which proposed Reliability Standard PER-006-1 and currently-effective Reliability Standards PER-003-1 and PER-005-2, collectively provide for formal training requirements for Generator Operators, Transmission Operators, and Balancing Authorities on Protection Systems and RAS, consistent with the objective of PRC-001-1.1(ii), Requirement R1. Further, as discussed below, the revisions to the definitions of OPA and RTA will also ensure that Transmission Operators, along with Reliability Coordinators, are familiar with and consider the functions and limitation of Protection Systems and RAS as they carry out their reliability functions.

1. Generator Operators

Currently-effective Reliability Standard PER-005-2, Requirement R6 and proposed Reliability Standard PER-006-1 address Generator Operator familiarity with the purpose and limitations of Protection System schemes. As discussed below, these standards provide more precise, auditable and enforceable requirements to meet the objective of Requirement R1 of PRC-001-1.1(ii) by: (1) focusing on formal training requirements; (2) clearly identifying the Generator Operator personnel that must receive training; (3) referencing both Protection Systems and RAS, instead of the undefined term “Protection System scheme;” and (4) clarifying the subject matter of the training on Protection Systems and RAS.

Reliability Standard PER-005-2, Requirement R6 and proposed PER-006-1 improve upon existing Reliability Standard PRC-001-1.1(ii) by establishing formal requirements for all relevant Generator Operator personnel on Protection Systems and RAS. Reliability Standard PER-005-2, Requirement R6, which became effective on July 1, 2016, provides that Generator Operators must use a systematic approach to develop and implement training for dispatch personnel at centrally located dispatch centers “on how their job function(s) impact the reliable operations of the BES during normal and emergency operations.”⁹ PER-005-2, Requirement R6 thus creates an affirmative obligation for Generator Operators, using a systematic approach, to (1) identify the manner in which the job functions of centrally-located dispatch personnel could impact the reliable operations of the BES, including among other things, as it relates to the functionality of Protection System schemes, and (2) develop and implement the necessary training to help ensure that the dispatchers carry out their job functions in a manner that will not adversely impact BES reliability. If the dispatch personnel’s job function can impact the reliable operation of Protection Systems and RAS, then the Generator Operator must train the dispatcher on the manner in which its job functions could impact Protection Systems and RAS.¹⁰

Recognizing that PER-005-2, Requirement R6 is limited to centrally-located dispatch personnel, the Project 2007-6.2 standard drafting team (“SDT”) developed proposed Reliability

⁹ The specific Generator Operator personnel that must be trained using a systematic approach under PER-005-2 are “[d]ispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator’s Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control.” PER-005-2, Requirement R6 was specifically developed to respond to a specific FERC directive from Order Nos. 693 and 742 to include training requirements for centrally-located dispatch personnel. *Mandatory Reliability Standards for the Bulk-Power System*, 72 Fed. Reg. 16416 (2007), FERC Stats. & Regs. ¶ 31,242, *order on reh’g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007); *System Personnel Training Reliability Standards*, Order No. 742, 133 FERC ¶ 61,159 75 Fed. Reg. 72664 (2010).

¹⁰ For instance, the centrally located dispatchers may need to understand the circumstances for which the functionality or limitations of a Protection System or RAS may create a risk under specific dispatch instructions.

Standard PER-006-1 to cover other Generator Operator personnel whose job functions necessitate that they be trained on the purpose and limitations of Protection System schemes. Specifically, “[p]lant 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.”¹¹ It is appropriate to train plant personnel with Real-time control of a generator as it is those individuals whose actions could impact the reliable operation of the BES and who, in turn, need to understand the functionality of Protection Systems and RAS and how they could affect the generation facility at which they have control.¹²

For these personnel, proposed PER-006-1 establishes a formal training requirement that that states:

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.

The proposed standard represents an improvement over existing PRC-001-1.1(ii) in several key respects. First, proposed PER-006-1 specifically references Protection Systems and RAS to avoid confusion as to the scope of the phrase “Protection System schemes,” which is used in PRC-001-1.1(ii). As noted above, as RAS are essentially schemes comprised of Protection Systems, the phrase “Protection System scheme” maps to both the NERC Glossary terms “Protection System” and “RAS.” To avoid any confusion as to whether RAS must be the subject of training

¹¹ Proposed Reliability Standard PER-006-1 Applicability section 4.1.1.1.

¹² Plant personnel that do not have Real-time control include, for example, fuel handlers, electricians, machinists, or maintenance staff.

under Requirement R1 of proposed PER-006-1, the SDT specifically referenced Protection Systems and RAS.

Proposed PER-006-1 also uses the phrase “operational functionality” instead of the phrase “purpose and limitations” used in PRC-001-1(ii) to more clearly identify the objective of the training. The phrase “operational functionality” focuses the required training on (1) the manner in which Protection Systems operate and prevent damage to BES Elements, and (2) the manner in which a RAS detects pre-determined BES conditions and automatically takes corrective actions. These are the key elements for which Generator Operator personnel need be aware to reliably operate their facilities. Training on the operational functionality of Protection Systems and RAS may include, among other things, the following topics: the 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, such as tripping/closing of breakers; tripping of a generator step-up transformer, or generator ramping/tripping control functions.

Additionally, PER-006-1 uses the phrase “that affect the output of the generating Facility(ies) it operates” in lieu of the phrase “applied in its area” from PRC-001-1.1(ii). First, NERC Reliability Standards do not use the concept of a Generator Operator area as is done for Balancing Authorities and Transmission Operators. Second, in contrast to Balancing Authorities and Transmission Operators, Generator Operators are not required to monitor or study BES reliability in their area and do not have the same wide area view of BES reliability to know the precise manner in which their facility could affect the BES in Real-time. The focus of Generator Operator reliability functions under NERC’s Reliability Standards is thus on the reliable operation of their generation facilities. Consistent with that reliability objective, the phrase “that affect the

output of the generating Facility(ies) it operates” properly tailors the scope of training required for Generator Operators. Under proposed Reliability Standard PER-006-1, Generator Operators must identify those Protection Systems and RAS that affect the output of their generation facilities and train the applicable personnel on the operational functionality of those Protection Systems and RAS.

The proposed standard does not specify a periodicity for the required training. NERC expects applicable entities to train their plant operating personnel prior to such personnel performing any Real-time operations. NERC also expects that Generator Operators update the training to reflect any changes to the operational functionality of Protection Systems and RAS.

2. Transmission Operators and Balancing Authorities

For Transmission Operators and Balancing Authorities, the reliability goal of Requirement R1 of PRC-001-1.1(ii) is addressed by the existing certification and training requirements in the PER group of Reliability Standards, specifically PER-003-1 and PER-005-2. As discussed below, these requirements help ensure that the relevant Transmission Operator and Balancing Authority personnel have the requisite knowledge of Protection Systems and RAS, among other things, to effectively carry out their reliability-related tasks. Further, these requirements help ensure that these personnel receive ongoing training to continue to reinforce the skills and knowledge required for those tasks. The proposed modifications to the definitions of OPA and RTA further the objective of PRC-001-1.1(ii), Requirement R1 by requiring that Transmission Operators consider the functions and limitations of Protection Systems and RAS when performing the OPAs and RTAs required under TOP Reliability Standards to determine whether there are any actual or expected SOL exceedances. These requirements are each discussed in turn, below.

i. PER-003-1 Certification Requirements

Pursuant to Reliability Standard PER-003-1, each Reliability Coordinator, Transmission Operator, and Balancing Authority must staff its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated minimum competency in the specified areas by obtaining and maintaining the relevant NERC credential. In support of NERC's mission to promote the reliability of the North American BPS, NERC administers a System Operator Certification Program to help ensure that BPS operators have a workforce of system operators that have the skills and qualifications to reliably operate the BPS.¹³ The System Operator Certification Program provides the framework for operators to obtain initial certification in one of the following four NERC credentials focusing on a specific functional area of system operations:

- 1) *Reliability Operator*, which focuses on the skills and knowledge required for Reliability Coordinator System Operators;
- 2) *Balancing, Interchange, and Transmission Operator*, which focusses on the skills and knowledge required for both Transmission Operator and Balancing Authority System Operators;
- 3) *Transmission Operator*, which focuses on the skills and knowledge required for Transmission Operator-only System Operators; and
- 4) *Balancing and Interchange Operator*, which focuses on the skills and knowledge required for Balancing Authority-only System Operators.

To obtain any of one these four credentials, an individual must pass the NERC System Operator Certification Exam applicable to that credential. The system operator certification exams test specific knowledge of job skills and Reliability Standards, and are designed to prepare

¹³ NERC maintains the required credentials for over 6,000 system operators working in system control centers across North America.

operators to handle the BPS during normal and emergency operations.¹⁴ Once an individual passes any of these exams, s/he must complete NERC-approved continuing education program courses and activities to maintain the certification.

The certification requirements in PER-003-1 help meet the objective of PER-001.1.1(ii), Requirement R1 by mandating that Transmission Operator and Balancing Authority System Operators demonstrate that they have the requisite knowledge about Protection Systems and RAS to maintain reliable operation in their area. Specifically, pursuant to Requirement R2 of PER-003-1, each Transmission Operator must staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in certain specified areas, including “protection and control”, by obtaining and maintaining valid NERC certification as a (1) Reliability Operator, (2) Balancing, Interchange and Transmission Operator, or (3) Transmission Operator.

The exams required for these certifications include, among other things, a specific focus on ensuring that such personnel can demonstrate competency in the area of protection and control.¹⁵ The protection and control area of the exam includes the following six topics: (1) analyzing the impact of protection equipment outages on system reliability; (2) ensuring special protective systems and RAS are enabled when needed for system reliability; (3) maintaining adequate protective relaying during all phases of system restoration; (4) analyzing relay targets, fault locaters and fault recorders to determine a proper restoration plan following a system event;

¹⁴ NERC conducts an extensive job analysis survey of certified operators across the industry to provide the basis for the exams. The job analysis survey results in an exam content outline for each of the exams. The exam content outline is the framework used to associate tasks to exam questions. NERC contracts with psychometric consultants who assist a working group of certified system operators in the development and maintenance of each exam. The exam working group consists of subject matter experts from all regions of North America.

¹⁵ See, e.g., NERC’s *Transmission Operator Certification Exam Content Outline 2015*, available at <http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Transmission%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf>.

(5) taking action in response to alarms from special protective schemes; and (6) scheduling system telecommunications, telemetering, protection, and control equipment outages to ensure system reliability.

Similarly, Requirement R3 provides that each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in certain areas by obtaining and maintaining valid NERC certification as a (1) Reliability Operator, (2) Balancing, Interchange and Transmission Operator, or (3) Balancing and Interchange Operator. While “protection and control” is not a specific area of competency listed in Requirement R3, each of the exams required to obtain the requisite certifications include topics related to Protection Systems.

Specifically, the exams for the (1) Reliability Operator certificate and (2) Balancing, Interchange and Transmission Operator certificate are also used for Reliability Coordinator and Transmission Operator System Operator certification, respectively, and thus include “protection and control” as an area of specific focus. The Balancing and Interchange Operator certificate exam, which is acceptable for Balancing Authority-only System Operators and does not include “protection and control” as a specified area of focus, nevertheless includes five of the six topics related to Protection Systems and RAS that are in the other exams. Specifically, the Balancing and Interchange Operator exam includes, among others, questions related to the following topics: (1) analyzing the impact of protection equipment outages on system reliability; (2) ensuring special protective systems and RAS are enabled when needed for system reliability; (3) maintaining adequate protective relaying during all phases of system restoration; (4) taking action in response

to alarms from special protective schemes; and (5) scheduling system telecommunications, telemetering, protection, and control equipment outages to ensure system reliability.¹⁶

ii. PER-005-2 Training Requirements

In addition to the certification requirements of PER-003-1, Reliability Standard PER-005-2 includes a number of requirements that collectively satisfy the objective of ensuring that Transmission Operators and Balancing Authorities are familiar with the purpose and limitations of Protection System schemes. First, pursuant to Requirement R1, each Transmission Operator and Balancing Authority must use a systematic approach to develop and implement a training program for its System Operators that, among other things, includes regular training on Protection Systems and RAS. Specifically, Requirement R1 requires Transmission Operators and Balancing Authorities to:

- Create a list of BES “company-specific Real-time reliability-related tasks based on a defined and documented methodology” that is updated on an annual basis (Part 1.1).
- Design and develop training materials based on the BES company-specific Real-time reliability-related task list (Part 1.2).
- Deliver the training to its System Operators (Part 1.3).
- Conduct an evaluation each calendar year of its training program to identify any needed changes to the training program and implement the identified changes (Part 1.4).

As the certification exams described above indicate, the Real-time reliability-related tasks of Transmission Operator and Balancing Authority System Operators relate to the operation of Protection Systems and RAS. The training programs required under Requirement R1 must thus include training on topics related to Protection Systems and RAS. The proposed revisions to the definitions of OPA and RTA, which, as further discussed below, require Transmission Operators

¹⁶ See NERC’s *Balancing and Interchange Operator Certification Exam Content Outline 2015*, available at <http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Balancing%20and%20Interchange%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf>.

to consider the functions and limitations of Protection Systems and RAS when performing OPAs and RTAs, further highlight that addressing issues related to Protection Systems and RAS are part of a Transmission Operator's Real-time reliability-related tasks and, in turn, should be included in the training program under PER-005-2, Requirement R1.

Additionally, Requirement R3 of PER-005-2 provides that Transmission Operators and Balancing Authorities must verify that its System Operators are capable of performing each of the company-specific Real-time reliability-related tasks identified under Requirement R1. This requirement helps ensure that the System Operator who is engaged in tasks associated with Protection Systems and RAS are capable of performing those tasks. In verifying that capability, Transmission Operators and Balancing Authorities must confirm that the System Operator understands the functions and limitations of the relevant Protection Systems and RAS.

Requirement R4 further reinforces these capabilities by requiring each Transmission Operator and Balancing Authority that “(1) has operational authority or control over Facilities with established [IROLs], or (2) has established protection systems or operating guides to mitigate IROL violations,” to provide its System Operators with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. Simulation training further enhances System Operator understanding of the relevant Protection Systems and RAS and the manner in which they impact BES operations.

Lastly, PER-005-2, Requirement R5 helps ensure that Transmission Operators and Balancing Authorities provide training to personnel who are not System Operators but have job functions that impact Real-time reliability-related tasks related to Protection Systems and RAS. Specifically, Requirement R5 provides that Transmission Operators and Balancing Authorities

must “use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified” pursuant to Requirement R1.¹⁷ As Operations Support Personnel perform OPAs and RTA in support of outage coordination and establishment of SOLs and IROLs, the required training should include material fostering an appropriate understanding of the functions and limitations of Protection Systems and RAS in their area, consistent with the objectives of PRC-001-1.1(ii), Requirement R1 and the modifications to the definition of OPA and RTA.

iii. Revised OPA and RTA Definitions

As discussed further in Exhibit E hereto, NERC also proposes modifications to the definitions of OPA and RTA to include the functions and limitations of Protection System and RAS as a required input for OPAs and RTAs. The modifications further the objective of PRC-001-1.1(ii), Requirement R1 by requiring entities to consider the functions and limitations of Protection Systems and RAS when assessing anticipated and potential conditions for next-day operations time frame (OPAs) and existing and potential operating conditions in Real-time (RTAs).

Pursuant to Reliability Standard TOP-002-4, Requirements R1 and R2, Transmission Operators are required to: (1) “have an [OPA] that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its [SOLs];” and (2) “have an Operating Plan(s) for next-day operations to address potential [SOL] exceedances identified as a result of its [OPA].”

¹⁷ Operations Support Personnel are “individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time operations of the Bulk Electric System.”

The definition of OPA is:

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 status or degradation; 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.)

To ensure that the functions and limitation of Protection Systems and RAS are inputs into the OPA, NERC is proposing to modify the definition as follows:

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.)¹⁸

Similarly, under Reliability Standard TOP-001-3, Requirements R13 and R14, each Transmission Operator is required to: (1) perform a RTA at least once every 30 minutes; and (2) initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or RTA. The current definition of RTA is:

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 Special Protection System status or degradation; Transmission outages, generator outages, Interchange; Facility Ratings, and identified phase angle and equipment limitations. (Real-time

¹⁸ NERC proposes to replace the term “Special Protection System” with “Remedial Action Scheme” to reflect the transition across NERC standards to using RAS. *See Notice of Filing of the North American Electric Reliability Corporation of the Revised Definition of Special Protection System*, filed May 13, 2016, and *N. Am. Elec. Reliability Corp.*, Docket No. RD16-5-000 (Jun. 23, 2016) (FERC unpublished letter order).

Assessment may be provided through internal systems or through third-party services.)

As with the modifications to the OPA definition, to ensure that the functions and limitation of Protection Systems and RAS are inputs into the RTA, NERC is proposing to modify the definition as follows:

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 **Special Protection System 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.)

3. Reliability Coordinators

Although PRC-001.1.1(ii), Requirement R1 does not apply to Reliability Coordinators, it is also important for Reliability Coordinator personnel to understand the functions and limitations of Protection Systems and RAS and consider that information when conducting OPAs and RTAs. The Reliability Coordinator has a central role in maintaining BES reliability, particularly with respect to helping to ensure that the BES is operated within SOLs and IROLs. As such, an understanding of Protection Systems and RAS is vital to the functional obligations of a Reliability Coordinator.

Accordingly, as is the case for Transmission Operators and Balancing Authorities, NERC's current Reliability Standards require the following to help ensure that Reliability Coordinator personnel have the requisite understanding of Protection Systems and RAS:

- Reliability Coordinators must staff their Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated competency in the area of "protection and control," among others, through the NERC System Operator Certification Program (PER-003-1, Requirement R1).

- Reliability Coordinators must train their System Operators, using a systematic approach, on their Real-time reliability related tasks, which may include tasks related to Protection Systems and RAS (PER-005-2, Requirement R1).
- Reliability Coordinators must verify that their System Operators are capable of performing each of the company-specific Real-time reliability-related tasks identified under PER-005-2, Requirement R1 (PER-005-2, Requirement R3).
- Reliability Coordinators that have (1) operational authority or control over Facilities with established IROLs, or (2) established protection systems or operating guides to mitigate IROL violations, must provide their System Operators emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES (PER-005-2, Requirement R4).
- Reliability Coordinators must provide training, using a systematic approach, to Operations Support Personnel on how their job function(s), including those related to Protection Systems and RAS, impact those BES company-specific Real-time reliability-related tasks identified pursuant to PER-005-2, Requirement R1.

In addition to these certification and training requirements, the modifications to the definitions of OPA and RTA require Reliability Coordinators to consider the functions and limitations of Protection Systems and RAS when conducting OPAs and RTAs to assess whether there are any actual or expected SOL or IROL exceedances, pursuant to Reliability Standard IRO-008-2, Requirements R1, R4 and R5. As the modifications to the definitions of OPA and RTA also apply to the Reliability Coordinator, they serve to enhance the manner in which the reliability objective of PRC-001-1.1(ii), Requirement R1 is met in NERC's Reliability Standards.

B. PRC-027-1 and Retirement of Requirements R3 and R4 of PRC-001-1.1(ii)

Proposed Reliability Standard PRC-027-1 is designed to improve upon and replace Requirements R3 and R4 of PRC-001-1.1(ii) in addressing the coordination of Protection Systems installed to detect and isolate Faults on the BES, such that those Protection Systems operate in their intended sequence during Faults. As noted above, coordinated Protection Systems enhance reliability by reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. Specifically, when

Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage.

Proposed Reliability Standard PRC-027-1 provides a clear set of Requirements that obligate entities to (1) implement a process for establishing and coordinating new or revised Protection System settings, and (2) periodically study Protection System settings that could be affected by incremental changes in Fault current to ensure the Protection Systems continue to operate in their intended sequence. Specifically, proposed PRC-027-1 consists of the following three requirements, each of which is discussed in greater detail below:

- Requirement R1 mandates that each Transmission Owner, Generator Owner, and Distribution Provider establish a process for developing new and revised Protection System settings for BES Elements to operate in the intended sequence during Faults. The process must include provisions for coordinating those settings with owners of electrically joined facilities.
- Requirement R2 mandates that, for each BES Element with a Protection System that could be affected by changes in Fault current, applicable entities must, every six years, determine whether the Protection System settings continue to be appropriate by: (1) performing a Protection System Coordination Study; (2) first evaluating whether there were any changes in Fault current that could affect the coordination of Protection System and, if so, performing a Protection System Coordination Study; or (3) a combination of the above two options. The proposed definition for the term Protection System Coordination Study is “[a]n analysis to determine whether Protection Systems operate in the intended sequence during Faults.”
- Requirement R3 requires applicable entities to implement the process established according to Requirement R1 for developing new or revised Protection System settings.

Collectively, these Requirements help ensure that Protection Systems are installed in a coordinated manner and operate in the intended sequence to isolate Faults on the BES.

Proposed Reliability PRC-027-1 improves upon Requirements R3 and R4 of PRC-001-

1.1(ii) by:

- Assigning the responsibility for performing coordination responsibilities to the owners of the Protection Systems whose functional obligations include setting, coordinating, and maintaining Protection Systems.

- Clarifying that proposed PRC-027-1 pertains to the coordination of Protection Systems associated with Fault clearing.
- Clarifying that the scope of the proposed standard applies to any Protection System installed to detect and isolate Faults on BES Elements, regardless of location (i.e., internal lines as well as tie-lines).
- Adding a Requirement that applicable entities establish and use a process to develop settings for their BES Protection Systems that must contain certain specified attributes.
- Adding a Requirement that applicable entities periodically perform Protection System Coordination Studies and/or review Fault current values for existing Protection Systems applied on BES Elements that are identified as being affected by changes in Fault current to determine whether the settings continue to be appropriate.

The following is a discussion of the applicability of the proposed standard and an analysis of each Requirement.

1. Applicability

Proposed Reliability Standard PRC-027-1 is applicable to Transmission Owners, Generator Owners, and Distribution Providers as these are the entities that own and install Protection Systems for the purpose of detecting Faults in the BES and have the functional obligations to maintain those Protection Systems. Transmission Owners own the largest number of Protection Systems installed for the purpose of detecting Faults on the BES. Generator Owners also have Protection Systems installed for the purpose of detecting Faults on the BES and 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. Lastly, Distribution Providers 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 the Distribution Provider.

As the owners of the Protection Systems, these entities should have the obligation to implement a coordinated process for developing new and revised Protection System settings and reviewing those setting on a periodic basis. Under the NERC Functional Model, the reliability tasks related to Transmission, Distribution, and Generation Ownership include design and maintenance of Protection Systems.¹⁹ These functions include developing Protection System settings, evaluating Protection System operations, and identifying Protection System Misoperations. As part of designing the Protection Systems, these entities must coordinate with their neighbors to ensure the Protection System operates in the intended sequence during Faults. In contrast, Transmission Operators and Generator Operators are only concerned with Protection Systems after they are placed in service.

In addition to clarifying the functional entities responsible for performing coordination responsibilities, proposed Reliability Standard PRC-027-1 also clarifies that the standard only applies to coordination of Protection Systems associated with Fault clearing. Aspects of protection coordination other than Fault coordination are addressed by 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 Reliability Standards:

¹⁹ The Functional Model provides (at p. 44) that Transmission Ownership includes the following task: “Design and authorize maintenance of transmission protective relaying systems and Special Protection Systems.” For Distribution, the Functional Model (at p. 46) lists the following as a task: “Design and maintain protective relaying systems, under-frequency load shedding systems, under-voltage load shedding systems, and Special Protection Systems that interface with the transmission system.” Lastly, the Functional Model (at p. 50), includes the following task for Generation Ownership: “Design and authorize maintenance of generation plant protective relaying systems, protective relaying systems on the transmission lines connecting the generation plant to the transmission system, and Special Protection Systems.” The Functional Model is available at: http://www.nerc.com/pa/Stand/Functional%20Model%20Archive%201/Functional_Model_V5_Final_2009Dec1.pdf

- Underfrequency Load shedding programs are addressed in PRC-006-2.
- Undervoltage Load shedding programs are addressed in PRC-010-2.
- Generator performance during declined frequency and voltage excursions is addressed in PRC-024-2.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-2.
- 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-004-5i.

Additionally, whereas Requirement R4 of PRC-001-1.1(ii) is limited to the coordination of Protection Systems on “major transmission lines,” the Requirements of PRC-027-1 apply to any Protection System installed to detect and isolate Faults on BES Elements, regardless of location, size, or whether they are tie-lines or internal lines. Eliminating the phrase “major transmission lines” also avoids the ambiguities involved in determining which lines are “major.”

2. Requirement R1

Requirement R1 mandates that each Transmission Owner, Generator Owner, and Distribution Provider establish a process for developing new and revised Protection System settings for BES Elements, such that those Protection Systems operate in the intended sequence during Faults (i.e., are properly coordinated). The process must include provisions designed to ensure that the settings are accurate and coordinated with owners of electrically joined facilities. Specifically, Requirement R1 provides:

- 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:
- 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.

This Requirement applies to changes to Protection System settings for any BES Element. Although the coordination of some Protection Systems may seem unnecessary, such as for a line that is protected solely by dual current differential relays, 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.

The following is a discussion of each Part of Requirement R1:

Part 1.1 helps ensure that applicable entities develop any new or revised Protection System settings using accurate and updated data by requiring them to review and update short-circuit

model data for the BES Element(s) under study.²⁰ 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. These studies form the basis for the development of Protection System settings as they provide the necessary Fault currents used by protection engineers to develop Protection System settings. Requiring a review and, if necessary, an update of short-circuit model data is thus necessary to ensure that the information that forms the basis of the development of Protection System settings is accurate and reflects the physical power system. The review of short-circuit model data would include a review of:

- applicable BES line, transformer, and generator impedances and Fault currents;
- 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; and
- where applicable, interconnected Transmission Owner, Generator Owner, and Distribution Provider information.

Part 1.2 further supports the development of accurate Protection System settings by requiring applicable entities to institute a systematic process for verifying that the Protection System settings are correct (i.e., that they meet applicable technical criteria, as defined by the entity). A review of the Protection System settings prior to implementation reduces the possibility of introducing human error. Examples of reviews include peer reviews, automated checking programs, and other entity-developed review procedures designed to verify the accuracy of the settings.

²⁰ Although Generator Owners and Distribution Providers may not have or maintain short-circuit models, NERC expects these entities to obtain the short-circuit model data from their Transmission Planners, Planning Coordinators, or Transmission Owners.

Part 1.3 addresses the coordination of Protection System settings between neighboring entities for BES Elements that electrically join Facilities owned by separate functional entities.²¹

Communication among neighboring entities is essential for identifying and resolving coordination issues prior to implementation of any new or revised Protection System settings. Part 1.3 creates the following obligations:

- Under Part 1.3.1, applicable entities proposing to change any Protection System setting for BES Elements that electrically join facilities owned by separate functional entities must include in their process provisions for providing proposed Protection System settings to their neighboring entities so as to allow those entities an opportunity to review those settings and determine whether there are any coordination issues.
- Under Part 1.3.2, applicable entities must include in their process provisions for responding to neighboring entities that provided them proposed Protection System setting under Part 1.3.1 by identifying any coordination issues or affirming that no such issues are present. These provisions ensure that the proposed settings are reviewed and that the initiating entity receives a response indicating whether there are any coordination issues to address prior to implementation.
- Under Part 1.3.3, applicable entities must include provisions in their process for verifying that any identified coordination issues are resolved with the neighboring entity prior to implementation, thereby minimizing any potential impact to BES reliability.²²
- Under Part 1.3.4, applicable entities must have provisions for communicating with neighboring entities 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. This Part recognizes that there may be instances under which changes to Protection Systems need to be made without the opportunity to coordinate with neighboring entities in the timeframe contemplated under

²¹ 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.

²² There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judgment. Further, 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. There could also be situations where protection philosophies differ between entities, but the entities can agree that these differences do not create coordination issues.

Parts 1.3.1 through 1.3.3. Nevertheless, those changes need to be coordinated with other entities to address any issues going forward.

3. Requirement R2

The reliability objective of Requirement R2 is to mitigate risks associated with the impact of changes in Fault current on Protection Systems installed to detect and isolate Faults on the BES. Over time, the accumulation of incremental changes in Fault current could affect the coordination of Protection Systems (i.e., the performance of the Protection System during Faults). Entities should thus be required to determine whether there were any changes in Fault current that affected the coordination of Protection Systems and, if so, adjust the settings as necessary to ensure the Protection System continues to operate in the intended sequence during Faults.

To that end, Requirement R2 mandates that, for BES Elements with Protection Systems that could be affected by changes in Fault current, applicable entities must, every six years, determine whether the Protection System settings continue to be appropriate by either: (1) performing a Protection System Coordination Study for each applicable BES Element to determine whether the Protection Systems continue to operate in the intended sequence during Faults; or (2) first evaluating whether there were any changes in Fault current at each BES Element that could affect the coordination of Protection Systems and, if so, performing a Protection System Coordination Study for that BES Element; or (3) using a combination of the above options to conduct a review at each applicable BES Element. Specifically, Requirement R2 provides as follows:

- R2.** 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; or

- Option 3: Use a combination of the above.

The components of Requirement R2 are discussed further below.

i. BES Element with Protection System Functions Identified in Attachment A

As noted above, the purpose of Requirement R2 is to periodically review Protection Systems that could be affected by changes in Fault current to determine whether the settings continue to be appropriate. Attachment 1 lists those Protection System functions that use current in their measurement to initiate tripping of circuit breakers and, as a result, changes in the magnitude of available Fault current could impact the coordination of these functions. Attachment A provides:

The following Protection System functions 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

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*. Examples of functions not included in Attachment A are

differential relays and Fault detectors as they do not meet the above criteria.²³ Under Requirement R2, if an applicable entity has any BES Elements with the Protection System functions listed in Attachment A, the entity must perform a review of the Protection Systems for that BES Element every six calendar years to determine whether Fault currents have affected the coordination of the Protection System and the settings need to be changed. Requirement R2, however, provides entities flexibility in the manner in which it conducts its review of those Protection Systems by providing three options, as discussed below.

ii. Option 1 – Performing Protection System Coordination Studies

To satisfy its obligation under Requirement R2, an applicable entity may choose to perform a full Protection System Coordination Study every six calendar years for each of its applicable BES Elements. The proposed definition for the new NERC Glossary term Protection System Coordination Study is “[a]n analysis to determine whether Protection Systems operate in the intended sequence during Faults.” If the results of the Protection System Coordination Study reveal that the Protection System requires revised settings to operate in its intended sequence during faults, the applicable entity would then initiate its process established pursuant to Requirement R1 to change the settings for those Protection Systems in accordance with the Protection System Coordination Study.

In performing a Protection System Coordination Study, applicable entities would evaluate current pickup levels, timing characteristics, impedance characteristics, and fault detector levels of relays to seek the best coordination possible of Protection Systems providing primary and backup protection of BPS Elements.

²³ For additional information regarding the Protection System functions listed in Attachment A, see the Supplemental Material section of the proposed standard.

iii. Option 2 – Comparison of Fault Current Values

Under Option 2, instead of immediately conducting Protection System Coordination Studies for each of its BES Elements with a Protection System function listed in Attachment A, an entity may first choose to compare present Fault current values at each of those BES Element to an established Fault current baseline to determine whether a Protection System Coordination Study is in fact necessary. This option provides entities the flexibility to determine whether there were any changes in Fault current at the BES Element that could affect Protection System coordination prior to expending its resources to perform a full Protection System Coordination Study.

Requirement R2 establishes a Fault current deviation of 15% or greater from a baseline established from the most recent Protection System Coordination Study as the threshold for determining whether a Protection System Coordination Study is necessary.²⁴ Specifically, if the Fault current comparison for a BES Element indicates a deviation of less than 15% from the established baseline, the applicable entity is not required to conduct a full Protection System Coordination Study for that BES Element. If, however, the Fault current comparison indicates a 15% percent or greater deviation on a BES Element, the applicable entity is then required to conduct a full Protection System Coordination Study for that BES Element to determine whether the Protection Systems for that BES Element continue to operate in the intended sequence during Faults.

NERC proposes a 15% deviation threshold for determining whether a Protection System Coordination Study is required under Option 2 based on generally-accepted margins for setting Protection Systems in which incremental Fault current changes would not interfere with

²⁴ As discussed below, entities seeking to use Option 2 for the initial performance of this Requirement must establish a baseline by the effective date of the standard based on short-circuit studies.

coordination. Accepted engineering practices require entities to consider proper margins while setting relays. Those margins are based on measurement errors, possible errors in fault studies, or unknown system configuration changes that can occur during system disturbances or short term operating conditions. Margins are used to help ensure that the Protection Systems operate as designed during any Fault condition and that relatively small (up to 15%) changes in Fault current do not interfere with that coordination. The 15% maximum deviation provides an entity with latitude, however, to choose a Fault current deviation threshold that is less than 15% to better match its protection philosophy, or other business considerations without creating undue risk to reliability.

If there is a Fault current deviation of 15% or greater and the results of the subsequent Protection System Coordination Study reveal that a Protection System requires revised settings to operate in its intended sequence during faults, the applicable entity would then initiate its process established pursuant to Requirement R1 to change the settings for those Protection Systems in accordance with the Protection System Coordination Study. As with Option 1, the time interval for conducting the Fault current comparison and any subsequent Protection System Coordination Study is six calendar years.

The Fault current values used in the comparison, whether three-phase or phase-to-ground Fault currents, should be determined with all generation in service and all transmission BES Elements in their normal operating state. Further, the Fault current baseline values used as a point of reference for the Fault current comparisons can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators, or Transmission Owners. As described in the footnote 1 of the proposed standards, 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.

With respect to the timing for establishing the Fault current baselines, footnote 1 in the proposed standard provides that an entity that elects to use Option 2 for its initial performance of this Requirement must establish its baseline by the effective date of the standard and update it each time it performs a Protection System Coordination Study. If an initial baseline was not established by the effective date of this Reliability Standard because the applicable entity chose Option 1 or installed a new BES Element, the entity may establish the baseline upon performing a Protection System Coordination Study. 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 following is a hypothetical example of how Option 2 would work in practice for a single BES Element: By the effective date of PRC-027-1, Entity X established an initial Fault current baseline of 10,000 amps at the bus to which the BES Element under study is connected. Consistent with Option 2, within six years of the effective date, Entity X performed a short-circuit review to determine the present Fault current value at the bus. The short-circuit review indicated that the Fault current increased to 11,250 amps, a 12.5% deviation. As the deviation was less than 15%, no Protection System Coordination Study was required for that BES Element. As such, no further action was required and Entity X satisfied its obligations under Requirement R2 for that first six-year interval.

As required by Requirement R2, six years later Entity X performed another short-circuit review to determine the present Fault current value at the bus. The baseline value for this Fault current comparison remains at 10,000 amps because Entity X did not perform a Protection System

Coordination Study as a result of the initial comparison and the baseline was not reset. The results of this second Fault current comparison indicated that the Fault current increased to 11,500 (a 15% deviation). To comply with Requirement R2, Entity X must now perform a Protection System Coordination Study, also to be completed within that six-year interval, and a new baseline of 11,500 amps would be established. If the Protection System Coordination Study indicates a need to modify the Protection System settings to ensure that the Protection System operates in the intended sequence, Entity X would use its process developed under Requirement R1 to effectuate those changes. If the Protection System Coordination Study does not indicate that setting changes are necessary despite the 15% deviation, Entity X is not required to take any further action (although its Fault current baseline is reset to 11,500 amps for future comparisons).²⁵

iv. Option 3 – Use Combination of Options 1 and 2

Option 3 provides entities the flexibility to use Option 1 at some BES Elements and Option 2 at other BES Elements based on the needs of its system. As Protection Systems at certain BES Elements are more susceptible to Fault current changes than others, applicable entities should have the latitude to choose between Option 1 and Option 2 for each BES Element. Where a BES Element is more susceptible to Fault current changes, the applicable entity may choose to bypass a Fault comparison (Option 2) and proceed straight to a Protection System Coordination Study (Option 1). In contrast, for BES Elements less susceptible to Fault current changes, the entity may choose Option 2 to do a Fault current comparison and potentially avoid the more resource intensive Protection System Coordination Study. An entity may, for example, choose Option 1 for all of its Facilities operated above 300 kV, while choosing to use Option 2 for its Facilities operated below

²⁵ Note that if, as a result of the first Fault current comparison, the entity decided to perform a Protection System Coordination Study even though there was only a 12.5% 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 but the baseline Fault current would be updated to 11,250 amps.

300 kV. No matter which option the entity chooses for each of its BES Elements, the entire cycle must be completed every six calendar years.

v. *Six-Year Time Interval*

NERC proposes a maximum of six-year intervals to perform the review under Requirement R2 so as to balance the resources required to perform Protection System Coordination Studies and the potential reliability impacts created by incremental changes of Fault current over time.²⁶ Performing Protection System Coordination Studies is a resource intensive activity. These studies require engineers to review Protection Systems at a number of substations to evaluate the coordination between the Protection Systems. This review includes performing fault simulations, creating impedance plots with relay characteristics, and time-overcurrent curve reviews where little or no change may have occurred during the six-year interval. For entities with many BES Elements with Protection System functions listed in Attachment A, significant time and personnel must be devoted to conducting Protection Systems Coordination Studies. To require entities to perform the Protection System Coordination Studies on shorter intervals may be overly burdensome without any additional reliability benefit.

NERC event analysis data supports the six-year intervals. Specifically, NERC reviewed its events analysis data from 2012-2015 to determine the number of instances in which Protection System coordination issues led to an event on the BES.²⁷ During 2012-2015, the number of events reported through the NERC Event Analysis process that had, as part of the event, more than one Misoperation due to incorrect settings is as follows:

- 2012 - three events out of a total of 45 Misoperation events (115 total qualified events)

²⁶ Entities may choose to do the review in shorter intervals.

²⁷ A coordination event was defined as an event that had more than one Protection System Misoperation. An event resulting from only one Misoperation is not a failure of coordination, but an isolated setting issue.

- 2013 - five events out of a total of 34 Misoperation events (140 total qualified events)
- 2014 - four events out of a total of 34 Misoperation events (171 total qualified events)
- 2015 - five events out of a total of 38 Misoperation events (148 total qualified events)

This data shows that Protection System coordination is not a significant issue on the BES in terms of number of events. From 2012 through 2015, only 11% of Misoperation events (17 events out of 151) and only 2.9% of total events (17 out of 574) involved Protection System coordination issues. Of the 17 events involving coordination issues, five were inter-company and 12 intra-company.²⁸ Given this data, the burden of requiring entities perform Protection System Coordination Studies at a time interval shorter than six years outweighs the reliability benefit of doing so.

As noted above, Requirement R2 is designed to capture incremental Fault changes that accumulate over time and could affect the coordination of Protection Systems eventually. Any changes to BPS Elements that require changes to Protection System settings will be addressed through the Requirement R1 process and implemented pursuant to Requirement R3. As such, significant accrued Fault current changes will not be likely without some evaluation due to the system changes. Requirement R2 provides assurance that entities do confirm coordination periodically where no change to a BES Element would have otherwise addressed changes to Protection Systems due to incremental Fault current changes.

4. Requirement R3

The purpose of Requirement R3 is to require applicable entities to use the process they developed under Requirement R1 for the development of any new or revised Protection System

²⁸ In total, only 12 events (out of 151 Misoperation events, or 7.9%) were found to be internal to an entity. Overall, that is 12 events out of 574 total events reported to Events Analysis, which is 2.1% of all events.

settings for BES Elements, whether as a result of a Protection System Coordination Study performed under Requirement R2 or the installation of a new BES Element with Protection Systems. Requirement R3 provides:

- 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.

As discussed above, using the Requirement R1 process helps ensure 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.

C. Retirement of Requirements R2, R5 and R6 of PRC-001-1.1(ii)

Consistent with FERC orders to eliminate redundancies in NERC's Reliability Standards,²⁹ NERC is proposing to retire the remaining Requirements in PRC-001-1.1(ii) – Requirements R2, R5, and R6 – as the reliability objectives of these Requirements are addressed by the revised TOP/IRO Reliability Standards submitted on March 25, 2015 and approved by FERC in Order No. 817.³⁰ While NERC did not specifically intend on addressing issues related to PRC-001-1.1(ii) when revising the TOP/IRO Reliability Standards, those revisions created certain redundancies with Requirements R2, R5, and R6 of PRC-001-1.1(ii). As such, these Requirements should be retired. The following is a discussion of the manner in which submitted Reliability Standards address Requirements R2, R5, and R6 of PRC-001-1.1(ii).

²⁹ See *Order Accepting with Conditions the Electric Reliability Organization's Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing*, 138 FERC ¶ 61,193 at P 81 (2012); *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147, 78 Fed. Reg. 78424 (2013).

³⁰ In Order No. 817, FERC approved nine revised TOP/IRO Reliability Standards – IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1, TOP-001-3, TOP-002-4, and TOP-003-3. *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 80 Fed. Reg. 73977 (2015).

1. PRC-001-1.1(ii), Requirement R2

The purpose of Reliability Standard PRC-001-1.1(ii), Requirement R2 is to require that, in the event of protective relay or equipment failures that reduce system reliability, Transmission Operators and Generator Operators: (1) notify relevant functional entities of such failures so that the relevant entities can act accordingly to maintain reliability; and (2) take timely corrective action to return the system to a stable state. Specifically, Requirement R2 provides:

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

Requirements in recently submitted Reliability Standards IRO-001-4, IRO-008-2, IRO-010-2, TOP-001-3, and TOP-003-3, however, obviate the need for Requirement R2 of PRC-001-1.1(ii). These TOP/IRO Reliability Standards address both the notification and corrective action components of PRC-001-1.1(ii), Requirement R2, as follows.

Notification of Protective Relay and Equipment Failures: The data specification Requirements in Reliability Standards TOP-003-3 and IRO-010-2 replace and improve upon the notification requirements in PRC-001-1.1(ii), Requirement R2, as discussed below. Reliability Standards TOP-003-3 and IRO-010-2 establish Requirements for the provision of information and data needed by Transmission Operators, Balancing Authorities, and Reliability Coordinators for reliable operations. Under those standards, the information and data that applicable functional entities must provide to Transmission Operators, Balancing Authorities, and Reliability

Coordinators includes, among other things, “notification of current Protection System and [SPS] status or degradation that impacts System reliability.” Such notifications would include failures of protective relays or equipment as such failures would impact the status and be considered a degradation of Protection Systems and SPS.³¹ These data specification standards are each discussed in turn, below.

Reliability Standard TOP-003-3 provides a mechanism for Transmission Operators and Balancing Authorities to obtain the data needed to fulfill their operational and planning responsibilities. TOP-003-3 consists of the following five Requirements:

- *Requirements R1 and R2* requires each Transmission Operator and Balancing Authority to maintain a documented specification for the data necessary for the Transmission Operator to perform its OPAs, Real-time monitoring, and RTAs, and for the Balancing Authority to perform its analysis functions and Real-time monitoring. The data specification must include, but is not limited to: (i) a list of data and information needed to support these analyses, monitoring, and assessments; (ii) provisions for the notification of current Protection System and Special Protection System status or degradation that impacts System reliability; (iii) a periodicity for providing data; and (iv) the deadline by which the respondent is to provide the indicated data.
- *Requirements R3 and R4* require each Transmission Operator (Requirement R3) and Balancing Authority (Requirement R4) to distribute its data specification to the entities that have the necessary data.
- *Requirement R5* requires each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification pursuant to Requirement R3 or R4 to satisfy the obligations of the documented data specification using: (i) a mutually agreeable format; (ii) a mutually agreeable process for resolving data conflicts; and (iii) a mutually agreeable security protocol.

Similarly, Reliability Standard IRO-010-2 provides a mechanism for the Reliability Coordinator to obtain the information and data it needs for reliable operations and to help prevent

³¹ The “equipment” referenced in PRC-001-1.1(ii), Requirement R2 refer, among other things, to the components of a Protection System, such as the voltage and current sensing devices providing inputs to protective relays or the Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

instability, uncontrolled separation, or Cascading outages. IRO-010-2 consists of the following three requirements:

- Requirement R1 provides that the Reliability Coordinator must maintain a documented specification for the data necessary for it to perform its OPAs, Real-time monitoring, and RTAs. The data specification must include: (i) a list of data and information necessary to support its performance of OPAs, Real-time monitoring, and RTAs, including non-Bulk Electric System data and external network data; (ii) provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability; (iii) a periodicity for providing data; and (iv) the deadline by which the respondent is to provide the indicated data.
- Requirement R2 provides that the Reliability Coordinator must distribute its data specification to entities that have the required data.
- Requirement R3 provides that each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification must satisfy the obligations of the documented specifications using a mutually-agreeable format, process for resolving data conflicts, and security protocol.

The notification obligations in Requirement R2 of PRC-001.1(ii) is thus subsumed in the data specification requirements in Reliability Standards TOP-003-3 and IRO-010-2. For Transmission Operators, Balancing Authorities and Reliability Coordinators to perform their respective analyses, monitoring, and assessment responsibilities under the TOP/IRO Reliability Standards,³² they must receive Protection System and SPS data from Generator Operators and Transmission Operators, among others. For example, to perform an OPA or RTA, the Transmission Operator and Reliability Coordinator must, by definition, consider the status and degradation of Protection Systems and SPS/RAS such as any protective relay or equipment failures. Comparably, for a Balancing Authority to satisfy its obligations under TOP-001-3, Requirement R11 to “monitor its Balancing Authority Area, including the status of [SPS] that impact generation or Load, in order to maintain generation-Load-interchange balance within its

³² See TOP-001-3, TOP-002-4, IRO-001-4, IRO-002-4, and IRO-008-3.

Balancing Authority Area and support Interconnection frequency,” the Balancing Authority must be aware of the status and degradation of Protection Systems and SPS. To that end, TOP-003-3 and IRO-010-2 specifically require Transmission Operators, Balancing Authorities, and Reliability Coordinators to obtain notifications on the status and degradation of Protection Systems and SPS from, among others, Generator Operators and other Transmission Operators, as is currently required under PRC-001-1.1(ii), Requirement R2. Accordingly, if there is any failure of a protective relay or other components of a Protection System, Transmission Operators, Balancing Authorities, and Reliability Coordinators will be notified.

Reliability Standards TOP-003-3 and IRO-010-2 improve upon PRC-001-1.1(ii), Requirement R2 by clarifying the timing of such notifications.³³ PRC-001-1.1(ii) does not include any time period associated with the notification, making it difficult for entities to know when to provide the notifications from a reliability perspective and for the ERO to measure compliance with the notification requirement. In contrast, TOP-003-3 and IRO-010-2 require the Transmission Operator, Balancing Authority, and Reliability Coordinator to set (i) the periodicity for providing data, and (ii) the deadline for respondents to provide the indicated data. Applicable entities would thus have certainty as to when the notifications must be provided and the ERO would be able to determine whether the notification was provided in a timely manner.

Providing Transmission Operators, Balancing Authorities, and Reliability Coordinators the authority to set the deadlines for providing the various data helps ensure that required notifications are provided within a timeframe designed to maintain reliable operations. Specifically, Transmission Operators, Balancing Authorities, and Reliability Coordinators must establish the

³³ In Order No. 693, FERC directed NERC to determine the appropriate timeframe for the notifications, as discussed further below. Order No. 693 at P 1445.

periodicity and deadlines in a data specifications to allow those entities to perform their functional obligations specified in NERC's Reliability Standards. If certain data is needed to perform an RTA, for instance, it must be provided every 30 minutes as Reliability Coordinators and Transmission Operators must perform RTAs every 30 minutes.³⁴ As RTAs, by definition, require Reliability Coordinators and Transmission Operators to consider the status and degradation of Protection Systems and SPS in assessing current operating conditions every 30 minutes, NERC expects that they would require entities to provide notification of protective relay or equipment failures within 30 minutes from the time the failure is discovered, if not sooner, and the Reliability Coordinator and Transmission Operator will include that information in its next RTA.

Corrective Action: Reliability Standards TOP-001-3 and IRO-001-4 more clearly address the reliability objective in PRC-001-1.1(ii), Requirement R2 of requiring Transmission Operators and Generator Operators to take corrective action to address protective relay and equipment failures that reduce system reliability. Pursuant to Reliability Standards TOP-001-3, Requirements R1 and R2, and IRO-001-4, Requirement R1, each Transmission Operator, Balancing Authority, and Reliability Coordinator must “act to maintain the reliability of its [area] via direct actions or by issuing Operating Instructions.”³⁵ Under these Requirements, if there is an event on the BES that reduces (or threatens to reduce) system reliability, such as protective relay or equipment failures, Transmission Operators, Balancing Authorities, and Reliability Coordinators have an affirmative obligation to take corrective action to maintain reliability, whether by their own actions

³⁴ See TOP-001-3, Requirement R13, IRO-008-2, Requirement R4.

³⁵ IRO-001-4, Requirement R1 uses the word “address,” not “maintain,” where TOP-001-3, Requirements R1 and R2 use the word “maintain.”

or by directing the actions of others through the issuance of an Operating Instruction.³⁶ As provided in TOP-001-3, Requirements R3-R6, and IRO-001-4, Requirements R2 and R3, any functional entity, including a Generator Operator or another Transmission Operator, that is the subject of such an Operating Instruction must: (1) comply with the Operating Instruction, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements; or (2) inform the entity that issued the Operating Instruction that it cannot comply with an Operating Instruction.

The affirmative requirements for Transmission Operators, Balancing Authorities, and Reliability Coordinators to act to maintain reliability in their area and issue Operating Instructions, when necessary, and for entities to comply with any Operating Instructions eliminate the need for a separate obligation such as that in PRC-001.1(ii), Requirement R2 for Generator Operators and Transmission Operators to take corrective action to address protective relay and equipment failures. Under the data specification requirements in Reliability Standards TOP-003-3 and IRO-010-2, if a Generator Operator or Transmission Operators notifies a Balancing Authority, Reliability Coordinator, or another Transmission Operator of a change in status or degradation of a Protection System or RAS (including protective relay or equipment failure that would reduce system reliability), compliance with Reliability Standards TOP-001-3 and IRO-001-4 requires the Transmission Operator, Balancing Authority, and/or Reliability Coordinator to maintain reliability by taking corrective action themselves or issuing an Operating Instruction to direct the notifying Generator Operator or Transmission Operator to take specific corrective action to resolve any operational issues resulting from the failure. If the Generator Operator or Transmission Operator

³⁶ As defined in the NERC Glossary, an Operating Instruction is “[a] command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System.”

is directed to take corrective action pursuant to an Operating Instruction, the Generator Operator or Transmission Operator must comply with those instructions according to the TOP/IRO standards.

Additionally, pursuant to TOP-002-4, Requirement R2 and R3, IRO-008-2, Requirements R2 and R3, if, as a result of an OPA, a Transmission Operator or Reliability Coordinator identifies an actual or expected SOL or IROL exceedance as a result of an issue on the system, it must develop an Operating Plan to mitigate any such exceedances and inform other functional entities of their role in the Operating Plan.³⁷ If the issue on the system relates to protective relay or equipment failures, the Operating Plan would address the corrective action necessary to mitigate the reliability impact of those failures and identify the appropriate entity to take such action so as to return the system to a secure and reliable state in a timely manner.

Further, pursuant to TOP-001-3, Requirement R14, each Transmission Operator must initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or RTA. Similarly, under IRO-008-2, Requirement R5, if the results of its RTA “indicate an actual or expected condition that results in, or could result in, a [SOL] or [IROL] exceedance within its Wide Area,” the Reliability Coordinator must notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan.

The framework established by the TOP/IRO Reliability Standards for requiring corrective action improves upon Requirement R2 of PRC-001-1.1(ii) by: (1) providing Reliability Coordinators, Balancing Authorities, and Transmission Operators the authority to determine the

³⁷ See TOP-001-3, Requirement R14, TOP-002-4, Requirement R2 and R3, IRO-008-2, Requirements R2 and R5.

appropriate corrective action based on the data specifications; and (2) setting clearer expectations for the timeframes under which the corrective action must be taken.³⁸ Requirement R2 of PRC-001-1.1(ii) assigns the responsibility to determine the appropriate corrective action to the Generator Operator and Transmission Operator whose protective relay or equipment failed. In contrast to the construct in PRC-001-1.1(ii), the framework in the TOP/IRO Reliability Standards appropriately assigns corrective actions to those functional entities in the best position to identify the corrective actions that are necessary to return the system to a secure and reliable state.

The TOP/IRO Reliability Standards assign the responsibility to determine the appropriate corrective actions to those functional entities – Reliability Coordinators, Balancing Authorities, and Transmission Operators – with a wide-area view of the BES and greater understanding of the actions necessary to return the system to a secure and reliable state. As explained above, the TOP/IRO standards establish a framework where, under TOP-003-3 and IRO-010-2, information and data regarding protective relay and equipment failures, among other things, are sent to those functional entities with a broader view of BES conditions – e.g., from a Generator Operator to Transmission Operator and Balancing Authority, and from a Transmission Operator to a Balancing Authority, Reliability Coordinator, or other Transmission Operators. Those functional entities are then required, pursuant to TOP-001-3, TOP-002-4, IRO-001-4, IRO-002-4, and IRO-008-2 to: (i) monitor and analyze BES conditions with the appropriate inputs,³⁹ (ii) determine whether any

³⁸ In Order No. 693, FERC directed NERC to determine the appropriate timeframe taking corrective action, as discussed further below. Order No. 693 at P 1441.

³⁹ Specifically, as described above, Transmission Operators are required to: (1) perform OPAs pursuant to TOP-002-4, Requirement R1; (2) perform RTAs every 30 minutes pursuant to TOP-001-3, Requirement R13; and (3) perform Real-time monitoring under TOP-001-3, Requirement R10. Similarly, Reliability Coordinators are required to: (1) perform OPAs pursuant to IRO-008-2, Requirement R1; (2) perform RTAs every 30 minutes pursuant to IRO-008-2, Requirement R4; and (3) perform Real-time monitoring pursuant to IRO-002-4, Requirement R3. Balancing Authorities are also required to perform Real-time monitoring pursuant to TOP-001-3, Requirement R11.

corrective action is necessary,⁴⁰ and (iii) either take that corrective action themselves or require other functional entities to take that corrective action.⁴¹ This framework improves reliability by placing the responsibility to determine the appropriate course of action with those entities best equipped to make those determinations through monitoring and analyzing system conditions.

Moreover, the framework established by the TOP/IRO Reliability Standards avoids the uncertainties associated with the timing element in PRC-001-1.1(ii) that Generator Operators and Transmission Operators take corrective action “as soon as possible.” The objective of the “as soon as possible” language is to require entities to take corrective action on a timely basis to maintain reliable operations without specifying a uniform (or one-size-fits-all) time period to be applied in every instance. A uniform timeframe for corrective action is not appropriate because various protective relays or equipment failures present different levels of risk to reliable operation. Whereas certain failures would cause more immediate reliability issues and entities should act in a shortened timeframe (e.g., within 30 minutes or less), other failures may not cause such immediate risks to reliability and entities should have additional time to correct the issue. Nevertheless, the phrase “as soon as possible” has created certain uncertainties for entities as to the timeframe under which they must take corrective action.

⁴⁰ Based on the results of the OPAs, Transmission Operators are required to develop an Operating Plan for next-day operations to address actual or expected SOL exceedances and inform entities of their role under the plan, pursuant to TOP-002-4, Requirements R2 and R3. If the results of an RTA or Real-time monitoring indicate an actual or expected SOL exceedance, the Transmission Operator must initiate its Operating Plan. Similarly, Reliability Coordinators must (1) develop a coordinated Operating Plan for next-day operations to address actual or expected SOL and IROL exceedances identified as a result of its OPA and inform entities of their role under the plan, pursuant to IRO-008-2, Requirements R2 and R3, and (2) if its RTA indicates an actual or expected condition that results in, or could result in, a SOL or IROL exceedance, notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, pursuant to IRO-008-2, Requirement R5.

⁴¹ Pursuant to Reliability Standards TOP-001-3, Requirements R1 and R2, and IRO-001-4, Requirement R1, each Transmission Operator, Balancing Authority, and Reliability Coordinator must “act to address the reliability of its [area] via direct actions or by issuing Operating Instructions.”

The TOP/IRO Reliability Standards, however, provide Reliability Coordinators, Balancing Authorities, and Transmission Operators the authority to set the appropriate timeframes for corrective action. If a Reliability Coordinator, Balancing Authority, or Transmission Operator issues an Operating Instruction directing other entities to take corrective action, the Operating Instruction would include a timeframe for such action. Similarly, if, as a result of an OPA, a Transmission Operator or Reliability Coordinator develops an Operating Plan to address actual or expected SOL or IROL exceedances, the Operating Plan could include the timeframe for any corrective action. The timeframes for any corrective action may thus be known to the entity required to take the action as well as the ERO in determining whether the applicable entities took corrective action on a timely basis.

This construct also improves reliability by assigning the responsibility to determine the appropriate timeframe to those functional entities with a wider view of the BES and greater understanding of the actions necessary to return the system to a secure and reliable state. As discussed above, Reliability Coordinators, Balancing Authorities, and Transmission Operators are responsible for monitoring and analyzing system conditions. As a result, these entities are in the best position to understand the appropriate timeframe for corrective action.

With the exception of IROL exceedances, the TOP/IRO Reliability Standards provide these entities the flexibility to develop the timeframe for corrective action based on their judgment of the facts and circumstances before them. As noted above, a uniform timeframe for all corrective action is not appropriate as different reliability issues present different levels of risks to reliable operation. Some issues require immediate attention to maintain reliability while others may be addressed on a longer time horizon. Nevertheless, Reliability Coordinators, Balancing Authorities, and Transmission Operators must set timeframes for corrective action consistent with their

obligations under the Reliability Standards to maintain reliable operation. Should the Transmission Operator or Reliability Coordinator, for instance, identify an actual or expected SOL exceedance, they must develop and initiate a coordinated Operating Plan to mitigate the SOL exceedance that include timeframes for corrective action to mitigate a SOL exceedance. Although the TOP standards do not specify a timeframe by which Transmission Operators must mitigate SOL exceedances (that are not also IROL exceedances), the Transmission Operator must take action or direct others to take action on a timely basis or it could potentially violate its obligation to maintain reliability in its area (TOP-001-3, Requirement R1).

For IROL exceedances, TOP standards specifically require corrective action within 30 minutes. Reliability Standard TOP-001-3, Requirement R12 prohibits Transmission Operators from “operat[ing] outside any identified [IROL] for a continuous duration exceeding its associated IROL T_v ,” which is not to exceed 30 minutes. Accordingly, if a protective relay or equipment failure would cause an IROL exceedance, the Transmission Operator must take corrective action itself, or issue an Operating Instruction to another entity to take corrective action, within 30 minutes, if not sooner, or else the Transmission Operator would potentially violate TOP-001-3, Requirement R12.

2. PRC-001-1.1(ii), Requirement R5

The reliability objective of Requirement R5 of PRC-001-1.1(ii) to coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others is now primarily addressed by Reliability Standard TOP-003-3, as well as Reliability Standards TOP-001-3, TOP-002-4, IRO-008-2, IRO-010-2, and IRO-017-1. As discussed further below, these Reliability Standards collectively require coordination and analysis

of changes in system conditions that would necessitate changes to, among other things, the Protection Systems of others.

Requirement R5 of PRC-001-1.1(ii) provides:

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

Given the scope of Reliability Standard TOP-003-3, however, there is no longer a reliability need for a separate Requirement in PRC-001.1(ii) to address advanced notification of changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others. As further described above, TOP-003-3 provides a mechanism for Transmission Operators to obtain the data needed to fulfill their operational and planning responsibilities, including the data needed to support their OPAs, Real-time monitoring, and RTAs. Among other things, a Transmission Operator must receive data from other entities regarding changes in generation, transmission, load, or operating conditions that could affect its system, including any such changes that may necessitate modifications to its Protection Systems or RAS.

Without such data, a Transmission Operator cannot perform an OPA, consistent with TOP-002-4, to effectively project system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. Similarly, without such data, a Transmission Operator cannot perform an RTA, consistent with TOP-001-3, to effectively assess

existing (pre-Contingency) and potential (post-Contingency) operating conditions. A Transmission Operator must thus include in its data specifications a requirement that other entities, such as Generator Operators and other Transmission Operators, provide notice of any changes in generation, transmission, load, or operating conditions that may necessitate changes to its Protection Systems or RAS. NERC anticipates that, as part of its OPAs and RTAs, the Transmission Operator would, where necessary, verify whether any of the changes noted by Generator Operators or other Transmission Owners necessitate changes to its Protection Systems and RAS in order to maintain reliable operation. If any such changes are necessary, the Transmission Operator would include them in its Operating Plan or otherwise make the necessary changes to the Protection Systems or RAS to satisfy its obligation under TOP-001-3, Requirement R1 to take action to maintain reliability in its area.

Additionally, the data specification requirements in IRO-010-2 and the obligations in IRO-008-2 that Reliability Coordinators perform OPAs and develop coordinated Operating Plans, where necessary, further the reliability objective of Requirement R5 of PRC-001.1(ii) by including coordination with the next-day Operating Plans provided by Transmission Operators and Balancing Authorities. Like the Transmission Operator, the Reliability Coordinator has an obligation to evaluate system conditions in the day-ahead timeframe (i.e., OPAs) and in Real-time (i.e., RTAs) pursuant to IRO-008-2 and obtain data from other functional entities to perform those evaluations pursuant to IRO-010-2. Under these standards, the Reliability Coordinator must receive data on changes to generation, transmission, load or operating conditions and evaluate, via OPAs and RTAs, whether any action is necessary to maintain reliability, including making changes to Protection Systems and RAS.

The outage coordination requirements of IRO-017-1 also enhance coordination between functional entities. Reliability Standard IRO-017-1 (Outage Coordination) is a new Reliability Standard designed to ensure that outages are properly coordinated in the operations planning time horizon and Near-Term Transmission Planning Horizon. The Reliability Coordinator must establish an outage coordination process that, among other things, provides for the communication of outage schedules, assignment of coordination responsibilities, and evaluation of the impact of transmission and generation outages. The process helps identify whether any outages necessitate changes in Protection Systems or RAS. Outage information is also an input to OPAs and RTAs.

3. PRC-001-1.1(ii), Requirement R6

Pursuant to PRC-001-1.1(ii), Requirement R6, Transmission Operators and Balancing Authorities must monitor the status of each SPS in their area and notify affected Transmission Operators and Balancing Authorities of any change in status. This reliability objective is now addressed in Reliability Standards TOP-001-3 and TOP-003-3, making a separate requirement in PRC-001-11(ii) unnecessary. Specifically, Requirements R10 and R11 of TOP-001-3 create an affirmative obligation for Transmission Operators and Balancing Authorities to monitor the status of SPS. Specifically, TOP-001-3, Requirements R10 and R11 provide as follows:

- R10.** Each Transmission Operator shall perform the following as necessary for determining [SOL] exceedances within its Transmission Operator Area:
 - 10.1.** Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and
 - 10.2.** Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.
- R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

The IRO standards also improve upon Requirement R6 of PRC-001-1.1(ii) by requiring the Reliability Coordinator to monitor the status of SPS. Specifically, IRO-002-4, Requirement R3 provides:

- R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

With respect to the notification element of Requirement R6 of PRC-001-1.1(ii), the data specification Requirements in TOP-003-3 and IRO-010-2 require entities to provide “notification of current Protection System and Special Protection System status or degradation that impacts System reliability.” A separate requirement in PRC-001-1.1(ii) requiring these notifications is therefore unnecessary.

D. Resolution of Outstanding FERC Directives Related to PRC-001-1.1(ii)

In Order No. 693, FERC approved Reliability Standard PRC-001-1 and also issued certain directives related to the meaning of the phrases “corrective action” and “as soon as possible” in Requirement R2.⁴² Accordingly, the scope of Project 2007-06.2 included consideration of outstanding FERC directives from Order No. 693 related to PRC-001-1.1(ii). The following is a description of each of FERC’s outstanding directives and a discussion of the manner in which the TOP/IRO Reliability Standards approved in Order No. 817 address each of those directives.

Clarifying the Term Corrective Action: In Order No. 693, paragraphs 1439-1441, FERC directed NERC to clarify that the term “corrective action” refers to “transmission operators taking operator control actions” and “does not refer to troubleshooting, repairing or replacing failed relays

⁴² Order No. 693 at PP 1433-49.

or equipment” performed by field maintenance personnel.⁴³ As discussed above, NERC proposes to retire Requirement R2 of PRC-001-1.1(ii) as the new TOP/IRO standards address, in a more precise fashion, the reliability objective of requiring Transmission Operators and Generator Operators to take corrective action following protective relay or equipment failures. Pursuant to Reliability Standards TOP-001-3, Requirements R1 and R2, and IRO-001-4, Requirement R1, each Transmission Operator, Balancing Authority, and Reliability Coordinator must “act to maintain the reliability of its [area] via direct actions or by issuing Operating Instructions.” The focus on action “to maintain [] reliability” and Operating Instructions, which is defined as a “command by operating personnel responsible for Real-time operation...to change or preserve the state, status, output, or input” of an Element or Facility of the BES, clarifies that the required action relates to operator control actions done on a timely basis to support reliable operations, not long-term action such as replacing failed relays and equipment.

Time for Corrective Action: In paragraphs 1444-1445 and 1449 of Order No. 693, FERC discussed the appropriate timeframe for “corrective action” and directed NERC to develop a modification to PRC-001 to clarify the timeframe for taking corrective action. FERC stated that the requirement for System Operators to take corrective action when protective relay or equipment failure reduces system reliability should be treated the same as the requirement for returning a system to a secure and reliable state after an IROL violation, i.e., as soon as possible, but no longer than 30 minutes after a violation as a longer time limit would place an entity in violation of relevant IROL or TOP Reliability Standards.⁴⁴ As discussed above, the timeframes for corrective action when protective relay or equipment failure reduces system reliability are now addressed in the

⁴³ Order No. 693 at PP 1439-41. Operator control actions include removing the facility without protection from service, generation re-dispatch, transmission re-configuration, etc.

⁴⁴ *Id.* at PP 1443, 1449.

TOP/IRO standards. Those standards provide Reliability Coordinators, Balancing Authorities, and Transmission Operators the authority to set the appropriate timeframes for corrective action, although those timeframes must be consistent with their other requirements, including their affirmative obligation to maintain reliability in their area and not to operate outside of an IROL for longer than 30 minutes.

Timeframe for Notification of Failures: FERC also directed NERC to modify the standard to determine a timeframe under which Generator Operators and Transmission Operators must provide the notifications of protective relay or equipment failures.⁴⁵ As discussed above, the timeframe for these notifications is now established in the data specifications required in TOP-003-3 and IRO-010-2. The periodicity and deadlines in the Transmission Operator's, Balancing Authority's, and Reliability Coordinator's data specifications must be set to allow those entities to perform their functional obligations. For instance, if certain data, such as the status of Protection Systems and RAS, is needed to perform an RTA, it must be provided every 30 minutes as Reliability Coordinators and Transmission Operators must perform RTAs every 30 minutes.⁴⁶

PRC-001 Measures and VSLs: FERC directed NERC to correct certain references in the Measures and VSLs to non-existent requirements.⁴⁷ As NERC proposes the retirement of PRC-001-1.1(ii), there is no need to correct these references.

E. Enforceability of the Proposed Reliability Standards

The proposed Reliability Standards include VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability

⁴⁵ *Id.* at P 1449.

⁴⁶ The TOP/IRO standards also address the comments of the California Public Utilities Commission as directed by FERC at Order No. 693 at P 1444.

⁴⁷ *Id.* at P 1446.

Standards. The VRFs and VSLs for the proposed Reliability Standards comport with NERC and FERC guidelines related to their assignment. Exhibit F provides a detailed review of the VRFs and VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

The proposed Reliability Standards also include measures that support each requirement by clearly identifying what is required and how the ERO will enforce the requirement. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

V. EFFECTIVE DATE

The proposed Reliability Standards and definitions, and the retirement of PRC-001-1.1(ii) are to become effective as set forth in the proposed Implementation Plans, provided in Exhibit B hereto. The proposed Implementation Plans for proposed Reliability Standards PER-006-1 and PRC-027-1, provided in Exhibit B hereto, provide that the proposed standards and definitions shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.. The 24-month implementation period will provide applicable entities sufficient time to (1) develop the training program required under proposed PER-006-1, (2) integrate the functions and limitations of Protection Systems and RAS into their OPAs and RTAs, and (3) develop and implement the process required by proposed PRC-027-1. Applicable entities need to devote considerable resources to the development of the program and

process required by the proposed standards and, in turn, require substantial lead time prior to implementation.

During the 24-month implementation period, entities must continue to comply with the Requirements in PRC-001-1.1(ii) until the proposed standards become effective, with the exception of Requirements R2, R5 and R6. Those Requirements, which, as discussed above, are being replaced by the TOP/IRO standards submitted on March 25, 2015 and approved by FERC in Order No. 817, are proposed to be retired on March 31, 2017. The new TOP/IRO standards become effective on April 1, 2017.

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests approval of:

- the proposed Reliability Standards and associated elements included in Exhibit A, effective as proposed herein;
- the proposed Implementation Plans included in Exhibit B;
- the proposed new and revised definitions to be incorporated into the NERC Glossary included in Exhibit A; and
- the retirement of Reliability Standard PRC-001-1.1(ii), effective as proposed herein.

Respectfully submitted,

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EXHIBITS A-B AND D-H

(Available on the NERC Website at

<http://www.nerc.com/FilingsOrders/ca/Canadian%20Filings%20and%20Orders%20DL/PRC-027%20and%20PER-006%20Exhibits.pdf>)

EXHIBIT C

Reliability Standards Criteria

The discussion below explains how the proposed Reliability Standards meet or exceed the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.

The proposed Reliability Standards achieve the specific reliability goals of: (1) maintaining 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; and (2) requiring registered entities to provide training to their relevant personnel on Protection Systems and Remedial Action Schemes (“RAS”) to help ensure that the BES is reliably operated. The proposed Reliability Standards articulate clear objectives for each of the areas.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply. The proposed Reliability Standards clearly articulate the actions that applicable entities must take to comply with the standards.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.

The Violation Risk Factors (“VRFs”) and Violation Severity Levels (“VSLs”) for the proposed Reliability Standards comport with NERC and FERC guidelines related to their assignment, as discussed further in Exhibit F. The assignment of the severity level for each VSL is consistent with the corresponding requirement. The VSLs do not use any ambiguous

terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.

The proposed Reliability Standards contain measures that support each requirement by clearly identifying what is required to demonstrate compliance. These measures help provide clarity regarding the manner in which the requirements will be enforced, and help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect “best practices” without regard to implementation cost or historical regional infrastructure design.

The proposed Reliability Standards achieve the reliability goals effectively and efficiently. The proposed Reliability Standards clearly articulate the objectives that applicable entities must meet and provide entities the flexibility to tailor their processes and plans required under the standard to best suit the needs of their organization.

6. Proposed Reliability Standards cannot be “lowest common denominator,” *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.

The proposed Reliability Standards do not reflect a “lowest common denominator” approach. To the contrary, the proposed Reliability Standards contains significant benefits for the Bulk-Power System. The requirements of the proposed Reliability Standards help ensure that

entities coordinate their Protection Systems with neighbors and are familiar with the operational functionality of the relevant Protection Systems and RAS.

- 7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.**

The proposed Reliability Standards apply throughout North America and do not favor one geographic area or regional model.

- 8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.**

The proposed Reliability Standards have no undue negative impact on competition. The proposed Reliability Standards require the same performance by each applicable entity. The standards do not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

- 9. The implementation time for the proposed Reliability Standard is reasonable.**

The proposed effective dates for the proposed Reliability Standards are just and reasonable and appropriately balance the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop and implement the necessary procedures and policies. The proposed implementation periods will allow applicable entities adequate time to meaningfully implement the requirements. The proposed effective dates are explained in the proposed Implementation Plan, attached as Exhibit B.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Reliability Standard development process.

The proposed Reliability Standards were developed in accordance with NERC's ANSI-accredited processes for developing and approving Reliability Standards. Exhibit G includes a summary of the development proceedings, and details the processes followed to develop the proposed Reliability Standards. These processes included, among other things, comment and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and additional ballots achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standards. No comments were received that indicated the proposed Reliability Standards conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.