

**Normes de fiabilité
(version anglaise)**

A. Introduction

1. **Title:** Protection System Misoperation Identification and Correction
2. **Number:** PRC-004-5(i)
3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Transmission Owner
 - 4.1.2 Generator Owner
 - 4.1.3 Distribution Provider
 - 4.2. **Facilities:**
 - 4.2.1 Protection Systems for BES Elements, with the following exclusions:
 - 4.2.1.1 Non-protective functions that are embedded within a Protection System.
 - 4.2.1.2 Protective functions intended to operate as a control function during switching.¹
 - 4.2.1.3 Special Protection Systems (SPS).
 - 4.2.1.4 Remedial Action Schemes (RAS).
 - 4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.
 - 4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.
 - 4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.
5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

¹ For additional information and examples, see the “Non-Protective Functions” and “Control Functions” sections in the Application Guidelines.

B. Requirements and Measures

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*
- 1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and
 - 1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and
 - 1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.
- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*
- 2.1** For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:
- 2.1.1** The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and
- 2.1.2** The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and
- 2.1.3** The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.
- 2.2** For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment, Operations Planning]*
- The identification of the cause(s) of the Misoperation; or
 - A declaration that no cause was identified.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Long-Term Planning]*
- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
 - Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.
- R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Long-Term Planning]*

- M6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

D. Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	High	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	High	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	High	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	High	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	High	<p>The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.</p> <p>OR</p> <p>(See next page)</p>	<p>The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.</p> <p>OR</p> <p>(See next page)</p>	<p>The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.</p> <p>OR</p> <p>(See next page)</p>	<p>The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation.</p> <p>OR</p> <p>The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5.</p> <p>OR</p> <p>(See next page)</p>

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	High	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.²

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC’s Order approving the interpretation of R1 and R3 is effective as of September 26, 2011

² (<http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf>).

Version	Date	Action	Change Tracking
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC’s Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add “...and generator interconnection Facility...”
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5	May 7, 2015	Adopted by NERC Board of Trustees	Revision under Project 2008-02.2
5(i)	June 22, 2015	Adopted by NERC Board of Trustees	Revision to VRF designations from “Medium” to “High” for Requirements R1 through R6, in compliance with the Federal Energy Regulatory Commission’s directive in N. Am. Elec. Reliability Corp., 151 FERC ¶ 61,129 (2015)

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter³ from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

“Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. ...Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization.”

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*⁴; July 2011.

“...a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry.”

The *State of Reliability 2014*⁵ report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 “Transmission Protective Relay System Performance Measuring Methodology⁶.” Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

³ (<http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf>).

⁴ “2011 Risk Assessment of Reliability Performance.” NERC. (http://www.nerc.com/files/2011_RARPR_FINAL.pdf, July 2011). Pg. 3.

⁵ “State of Reliability 2014.” NERC. (<http://www.nerc.com/pa/Stand/Pages/ReliabilityCoordinationProject20066.aspx>). May 2014. Pg. 18 of 106.

⁶ “Transmission Protective Relay System Performance Measuring Methodology.” Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a “Protection System” is defined in the *Glossary of Terms Used in NERC Reliability Standards* (“NERC Glossary”) as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

Composite Protection System – *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element’s Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element’s multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element’s total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker’s Composite Protection System. Considering breaker failure protection to be part of another Element’s Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the “Slow Trip” criteria of the Misoperation definition.

- An example of a correct operation of the breaker’s Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line’s Composite Protection System.
- An example of a correct operation of the breaker’s Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker’s Composite Protection System.
- An example of an “Unnecessary Trip – During Fault” is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

- 1. Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
- 2. Failure to Trip – Other Than Fault** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. **Slow Trip – During Fault** – *A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System.*
4. **Slow Trip – Other Than Fault** – *A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System.*
5. **Unnecessary Trip – During Fault** – *An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. **Unnecessary Trip – Other Than Fault** – *An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element’s total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a “Failure to Trip” or a “Slow Trip” does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a “Failure to Trip – During Fault” Misoperation as long as another component of the transformer's Composite Protection System operated.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a “Failure to Trip – During Fault” Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one “Failure to Trip – During Fault” Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – During Fault” category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The “Failure to Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – Other Than Fault” category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

Example 3c: A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation

times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

Example 4: A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator's Composite Protection System, but not of the transmission line's Composite Protection System.

The "Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

Example 5: An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

Example 5b: An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.

Example 5c: If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

Example 6a: An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.

Example 6b: Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.

Example 6c: An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.

Example 6d: Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

Example 6e: A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

Example 7a: A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

Example 7c: A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

Example 8a: The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.

Example 8b: The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

Example 8c: Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: “In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties.” The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

Example R1a: The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device

owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*⁷ which states:

“In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation.”

The following is an example of a condition that is not a Misoperation.

⁷ “Misoperations Report.” Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). April 1, 2013. Pg. 37 of 40.

Example R1b: A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

Example R2a: Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

Example R2b: A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

Example R2c: Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

Example R4a: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize

that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.⁸

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

Example R4b: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.

Example R4c: A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

⁸ NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). Figure 15: NERC Wide Misoperations by Cause Code. Pg. 22 of 40.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

Example R5a: Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

Example R5b: Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

Example R5c: Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.

A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

Example R5d: Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.

Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

Example R5e: The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

Example R5g: The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation)

through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

Example R6a: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

Example R6b: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.

CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

Example R6c: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.

CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

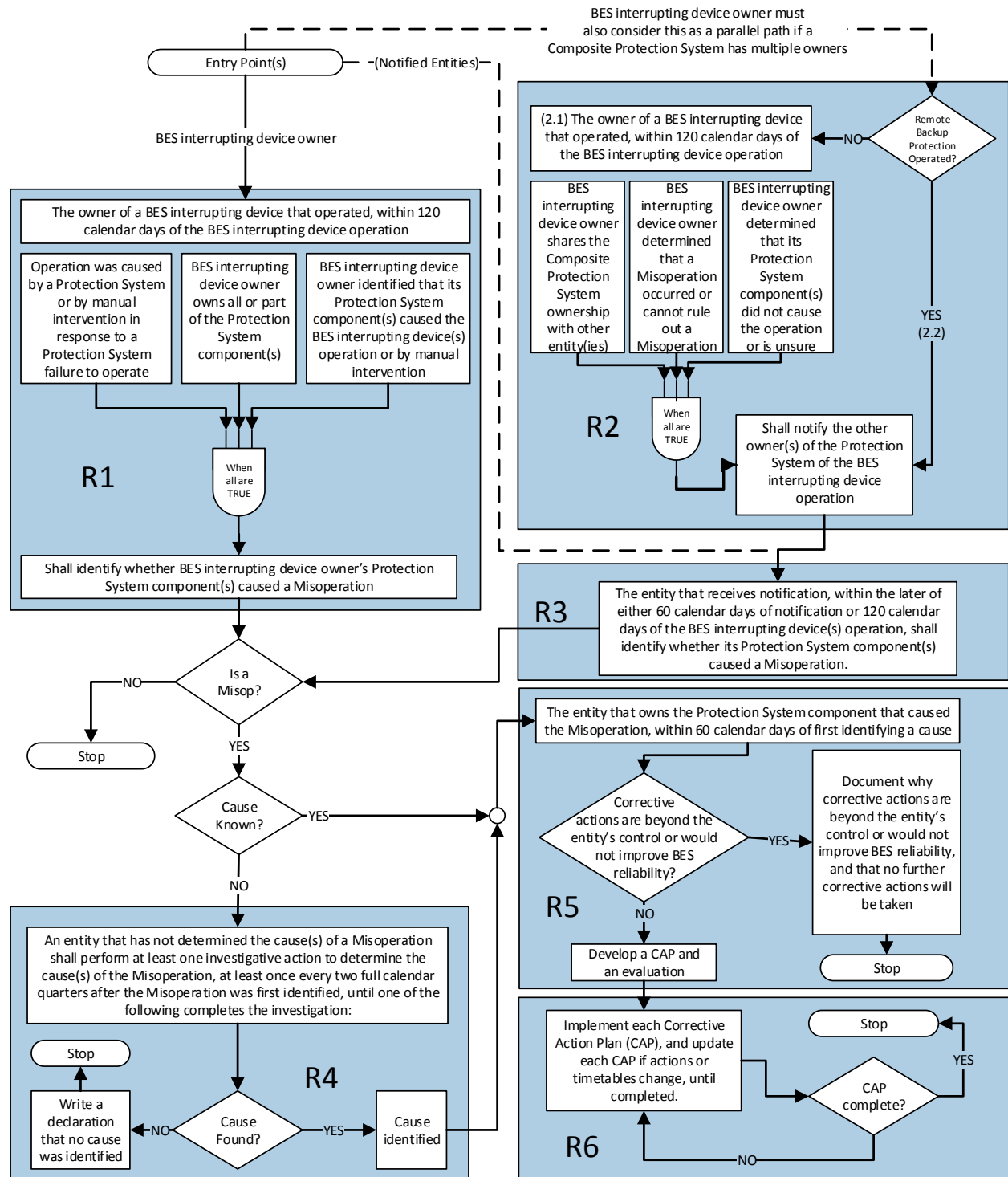
Example R6d: Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.

CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Rationale

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

Rationale for Introduction

The only revisions made to version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

Rationale for Applicability

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for “common- mode failure” type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-004-5(i) — Protection System Misoperation Identification and Correction

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-004-5(i)	All	04/02/2017	

Appendix PRC-004-5(i)-QC-1

Specific provisions applicable in Québec for standard PRC-004-5(i) – Protection System Misoperation Identification and Correction

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of this appendix must be read jointly for comprehension and interpretation purposes. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. **Title:** No specific provisions.

2. **Number:** No specific provisions.

3. **Purpose:** No specific provisions.

4. **Applicability:**

4.1. **Functional Entities**

No specific provisions.

4.2. **Facilities**

Replace all references to Bulk Electric System (BES) with Main Transmission System (RTP), with the exception of 4.2.1.4, which is retired, and 4.2.1.5, which is replaced as follows:

4.2.1.4. [In the French-language context] Subsection 4.2.1.4 is retired given that *plan de défense* (Remedial Action Scheme) is replaced with *automatisme de réseau* to mean the same thing and already included in 4.2.1.3.

4.2.1.5 Protection Systems for individual generating units of Dispersed Power Producing Resources if the aggregate nameplate rating of those RTP Facilities affected by Misoperation does not exceed 75 MVA.

5. **Effective date:**

5.1. Adoption of the standard by the Régie de l'énergie: December 11, 2020

5.2. Adoption of this appendix by the Régie de l'énergie: December 11, 2020

5.3. Effective date of the standard and of this appendix in Québec: April 1, 2021
Implementation date for non-BPS RTP Facilities: July 1, 2022

B. Requirements and Measures

Replace all references to Bulk Electric System (BES) with Main Transmission System (RTP).

C. Compliance

1. **Compliance Monitoring Process**

1.1. **Compliance Enforcement Authority**

In Québec, "Compliance Enforcement Authority" means the Régie de l'énergie in its roles of monitoring and enforcing compliance with respect to the Reliability Standard and to this appendix.

1.2. **Evidence Retention**

No specific provisions.

Appendix PRC-004-5(i)-QC-1

Specific provisions applicable in Québec for standard PRC-004-5(i) – Protection System Misoperation Identification and Correction

1.3. Compliance Monitoring and Assessment Processes

The Régie de l'énergie establishes the monitoring processes used to evaluate data or information for the purpose of determining compliance or non-compliance with the Reliability Standard and with this appendix.

1.4. Additional Compliance Information

No specific provisions.

D. Table of Compliance Elements

Replace all references to Bulk Electric System (BES) with Main Transmission System (RTP).

E. Regional Variances

No specific provisions.

F. Interpretations

No specific provisions.

G. Associated Documents

No specific provisions.

Guidelines and Technical Basis

No specific provisions.

Rationale

No specific provisions.

Version history

Version	Date	Action	Change tracking
1	December 11, 2020	New appendix	New

A. Introduction

1. **Title:** Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
2. **Number:** PRC-005-6
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Transmission Owner
 - 4.1.2 Generator Owner
 - 4.1.3 Distribution Provider
 - 4.2. **Facilities:**
 - 4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.
 - 4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, except for generators identified through Inclusion I4 of the BES definition, including:
 - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
 - 4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:

4.2.6.1 Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above.

4.2.7 Automatic Reclosing¹, including:

4.2.7.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.²

4.2.7.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.7.3 Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

5. Effective Date: See the Implementation Plan for this standard.

6. Definitions Used in this Standard:

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Supervisory relay(s) or function(s) – relay(s) or function(s) that perform voltage and/or sync check functions that enable or disable operation of the reclosing relay
- Voltage sensing devices associated with the supervisory relay(s) or function(s)

¹ Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

² The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

- Control circuitry associated with the reclosing relay or supervisory relay(s) or function(s)

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System
- Any one of the four specific elements of Automatic Reclosing
- Any one of the two specific elements of Sudden Pressure Relaying

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
 - 1.2.** Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.
- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented PSMP in accordance with Requirement R1.
- For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)
- For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5. (Part 1.2)
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the

time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5. *[Violation Risk Factor: High]*
[Time Horizon: Operations Planning]

- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High]* *[Time Horizon: Operations Planning]*
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the PSMP for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium]* *[Time Horizon: Operations Planning]*
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated PSMP, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	<p>The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p>OR</p> <p>The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (Part 1.2).</p>	<p>The entity failed to establish a PSMP.</p> <p>OR</p> <p>The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).</p> <p>OR</p> <p>The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1).</p>
R2	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	<p>The entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p>OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p>OR</p>

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: <ul style="list-style-type: none"> • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. Regional Variances

None.

E. Interpretations

None.

Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-6 Protection System Maintenance*, Protection System Maintenance and Testing Standard Drafting Team (July 2015)
2. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758*, NERC System Protection and Control Subcommittee (December 2013)
4. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – Supplemental Information to Support Project 2007-17.3: Protection System Maintenance and Testing* (October 31, 2014)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	February 7, 2006	Adopted by NERC Board of Trustees	<ol style="list-style-type: none"> 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.
1	March 16, 2007	PRC-005-1 Approved by FERC. Docket No. RM06-16-000	

Version	Date	Action	Change Tracking
1a	February 17, 2011	Adopted by NERC Board of Trustees	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17
1a	September 26, 2011	Approved by FERC. Docket No. RD11-5-000	
1b	November 5, 2009	Adopted by NERC Board of Trustees	Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10
1b	February 3, 2012	FERC Order approving revised definition of “Protection System”	Per footnote 8 of FERC’s order, the definition of “Protection System” supersedes interpretation “b” of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013) <i>See N. Amer. Elec. Reliability Corp., 138 FERC ¶ 61,095 (February 3, 2012).</i>
1b	February 3, 2012	PRC-005-1b Approved by FERC. Docket No. RM10-5-000	
1.1b	May 9, 2012	Adopted by NERC Board of Trustees	Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility
1.1b	September 19, 2013	PRC-005-1.1b Approved by FERC. Docket No. RM12-16-000	
2	November 7, 2012	Adopted by NERC Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0

Version	Date	Action	Change Tracking
2	October 17, 2013	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section. (no change to standard version number)
2	December 19, 2013	PRC-005-2 Approved by FERC. Docket No. RM13-7-000	
2	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number)
2(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
2(i)	May 29, 2015	PRC-005-2(i) Approved by FERC. Docket No. RD15-3-000	
2(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No. 758 to include Automatic Reclosing in maintenance programs

Version	Date	Action	Change Tracking
3	February 12, 2014	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved errata changes to correct capitalization of certain defined terms within the definitions of “Unresolved Maintenance Issue” and “Protection System Maintenance Program”. The changes will be reflected in the definitions section of PRC-005-3 for “Unresolved Maintenance Issue” and in the NERC Glossary of Terms for “Protection System Maintenance Program”. (no change to standard version number)
3	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number)
3	January 22, 2015	PRC-005-3 Approved by FERC. Docket No. RM14-8-000	
3(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
3(i)	May 29, 2015	PRC-005-3(i) Approved by FERC. Docket No. RD15-3-000	
3(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 13, 2014	Adopted by NERC Board of Trustees	Added Sudden Pressure Relaying in response to FERC Order No. 758
4	Sept 17, 2015	PRC-005-4 Approved by FERC. Docket No. RM15-9-000	

Version	Date	Action	Change Tracking
5	May 7, 2015	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources.
6	November 5, 2015	Adopted by NERC Board of Trustees	Revised to add supervisory relays, the voltage sensing devices, and the associated control circuitry to Automatic Reclosing in accordance with the directives in FERC Order 803.
6	December 18, 2015	FERC Letter Order approving PRC-005-6. Docket No. RD16-2-000.	

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ³	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2). 	12 Calendar Years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

³ For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ³	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2). 	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: <ul style="list-style-type: none"> • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). 	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with ac measurements that are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

<p style="text-align: center;">Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)</p> <p style="text-align: center;">Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

<p align="center">Table 1-4(b)</p> <p align="center">Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries</p> <p align="center">Excluding distributed UFLS and distributed UVLS (see Table 3)</p> <p align="center">Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

<p align="center">Table 1-5</p> <p align="center">Component Type - Control Circuitry Associated With Protective Functions</p> <p align="center">Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5)</p> <p align="center">Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

<p align="center">Table 2 – Alarming Paths and Monitoring</p> <p align="center">In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
<p>Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.</p> <p>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.</p>	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
<p>Alarm Path with monitoring:</p> <p>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.</p>	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	<p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate. <p>For microprocessor relays:</p> <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. <p>Alarming for power supply failure (See Table 2).</p>	12 Calendar Years	<p>Verify:</p> <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • AC measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). 	12 Calendar Years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
<ul style="list-style-type: none"> Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

<p align="center">Table 4-1</p> <p align="center">Maintenance Activities and Intervals for Automatic Reclosing Components</p> <p align="center">Component Type – Reclosing and Supervisory Relay</p> <p>Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
<p>Any unmonitored reclosing relay or supervisory relay not having all the monitoring attributes of a category below.</p>	<p>6 Calendar Years</p>	<p>Verify that settings are as specified.</p> <p>For non-microprocessor reclosing or supervisory relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate <p>For microprocessor reclosing or supervisory relays:</p> <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing. <p>For microprocessor supervisory relays:</p> <ul style="list-style-type: none"> • Verify acceptable measurement of power system input values.
<ul style="list-style-type: none"> • Monitored microprocessor reclosing relay or supervisory relay with the following: Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). <p>For supervisory relay:</p> <ul style="list-style-type: none"> • Voltage waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. 	<p>12 Calendar Years</p>	<p>Verify:</p> <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing. <p>For supervisory relays:</p> <ul style="list-style-type: none"> • Verify acceptable measurement of power system input values.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing and Supervisory Relay		
Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Monitored microprocessor reclosing relay or supervisory relay with preceding row attributes and the following: <ul style="list-style-type: none"> Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2). For supervisory relay: <ul style="list-style-type: none"> Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). 	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a)

Maintenance Activities and Intervals for Automatic Reclosing Components

Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that are NOT an Integral Part of an RAS

Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b)

Maintenance Activities and Intervals for Automatic Reclosing Components

Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that ARE an Integral Part of an RAS

Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 4-3 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Voltage Sensing Devices Associated with Supervisory Relays Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-3, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that voltage signal values are provided to the supervisory relays.
Voltage sensing devices that are connected to microprocessor supervisory relays with ac measurements that are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure. (See Table 2)	No periodic maintenance specified	None.

<p style="text-align: center;">Table 5 Maintenance Activities and Intervals for Sudden Pressure Relaying</p>		
<p style="text-align: center;">Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Rationale:

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

Rationale for revisions to Automatic Reclosing:

To address directives from FERC Order No. 803 addressing Automatic Reclosing, the definition for Automatic Reclosing was revised to add supervisory relays, the associated voltage sensing devices, and the associated control circuitry.

Rationale for revisions to Component Type:

With the revision of the definition of Automatic Reclosing, there are four specific elements of this definition, rather than two as stated in the prior version.

Appendix PRC-005-6-QC-1

Specific provisions applicable in Québec for standard PRC-005-6 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of this appendix must be read jointly for comprehension and interpretation purposes. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. **Title:** No specific provisions.

2. **Number:** No specific provisions.

3. **Purpose:** No specific provisions.

4. **Applicability:**

4.1. **Functional Entities**

No specific provisions.

4.2. **Facilities**

Replace all references to “Bulk Electric System (BES)” with “Main Transmission System (RTP)”, including the footnotes 1 and 2.

The subsections of Section 4.2 apply, with the exception of the following subsections, which take precedence:

4.2.2. Protection Systems for underfrequency load shedding (UFLS) systems.

4.2.5. Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the RTP, except for Dispersed Power Producing Resources, including the following:

4.2.6. Protection Systems and Sudden Pressure Relaying for the following RTP generation Facilities in the case of Dispersed Power Producing Resources:

4.2.6.1 Protection Systems and Sudden Pressure Relaying for Facilities mentioned in point b) of the Dispersed Power Producing Resources definition in the Glossary of Terms Used in NERC Reliability Standards (the “Glossary”).

5. **Effective date:**

5.1. Adoption of the standard by the Régie de l'énergie: December 11, 2020

5.2. Adoption of this appendix by the Régie de l'énergie: December 11, 2020

5.3. Effective date of the standard and of this appendix in Québec: April 1, 2021

BPS Protection Systems that were already covered by PRC-005-2: the implementations dates for the Requirements are those of PRC-005-2 (see tables 1a and 1b of this Appendix).

RTP Protection Systems that were not included in PRC-005-2: the implementation dates for the Requirements are specified in tables 2a and 2b of this Appendix. These tables consider not only the equipment that is now covered because it is part of the RTP (including the BPS), but also all Elements newly covered by PRC-005-6, i.e., Automatic Reclosing, Sudden Pressure Relaying, Protection Systems installed as Remedial Action Schemes (RAS) and not

Appendix PRC-005-6-QC-1

**Specific provisions applicable in Québec for standard
PRC-005-6 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying
Maintenance**

corresponding to the definition of SPS, and the Protection Systems of Dispersed Power Producing Resources.

Table 1a – Implementation dates of PRC-005-2, applicable only to BPS

Requirements	Implementation dates in Québec
R1, R2, R5	January 1, 2017
R3, R4	See table below

Table 1b – Implementation dates of PRC-005-2 for requirements R3 and R4

Maximum Maintenance Interval (tables 1 to 3)	Applicability	Implementation dates in Québec
≤1 year	100% maintenance required	January 1, 2017
1 year to 2 years	100% maintenance required	April 1, 2017
Up to 3 years	30% maintenance required	April 1, 2017
	60% maintenance required	April 1, 2017
	100% maintenance required	April 1, 2018
Up to 6 years	30% maintenance required	April 1, 2017
	60% maintenance required	April 1, 2019
	100% maintenance required	April 1, 2021
Up to 12 years	30% maintenance required	April 1, 2019
	60% maintenance required	April 1, 2023
	100% maintenance required	April 1, 2027

**Table 2a – Implementation dates for PRC-005-6, applicable to the RTP and now covering
Automatic Reclosing, Sudden Pressure Relaying, Protection Systems installed as Remedial
Action Schemes (RAS), but not included in the definition of SPS, and Protection Systems
for Dispersed Power Producing Resources**

Requirements	Implementation dates in Québec
R1, R2 and R5	October 1, 2022
R3 and R4	see table below

Appendix PRC-005-6-QC-1

**Specific provisions applicable in Québec for standard
PRC-005-6 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying
Maintenance**

Table 2b – Implementation dates of PRC-005-6 for requirements R3 and R4

Maximum Maintenance Interval (tables 1 to 5)	Applicability	Implementation dates in Québec
≤1 year	100% maintenance required	April 1, 2023
1 year to 2 years	100% maintenance required	July 1, 2023
Up to 3 years	30% maintenance required	July 1, 2023
	60% maintenance required	July 1, 2024
	100% maintenance required	August 1, 2025
Up to 6 years	30% maintenance required	April 1, 2024
	60% maintenance required	April 1, 2025
	100% maintenance required	April 1, 2027
Up to 12 years	30% maintenance required	April 1, 2026
	60% maintenance required	October 1, 2028
	100% maintenance required	April 1, 2033

6. Definitions Used in this Standard

No specific provisions.

B. Requirements and Measures

No specific provisions.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

In Québec, “Compliance Enforcement Authority” means the Régie de l’énergie in its roles of monitoring and enforcing compliance with respect to the Reliability Standard and to this appendix.

1.2. Evidence Retention

No specific provisions.

1.3. Compliance Monitoring and Assessment Processes

The Régie de l’énergie establishes the monitoring processes used to evaluate data or information for the purpose of determining compliance or non-compliance with the Reliability Standard and with this appendix.

1.4. Additional Compliance Information

No specific provisions.

Appendix PRC-005-6-QC-1

Specific provisions applicable in Québec for standard PRC-005-6 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Table of Compliance Elements

No specific provisions.

D. Regional Variances

No specific provisions.

E. Interpretations

No specific provisions.

Supplemental Reference Documents

No specific provisions.

Tables 1-1 to 1-5

Replace all references to the term “non-BES” with the term “non-RTP.”

Table 2

No specific provisions.

Table 3

Replace all references to the term “non-BES” with the term “non-RTP.”

Tables 4-1 to 5

No specific provisions.

Attachment A

No specific provisions.

Version history

Version	Date	Action	Change tracking
1	December 11, 2020	New appendix	New

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings
2. **Number:** PRC-024-2
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
 - 4.1. Generator Owner
5. **Effective Date:**

See the Implementation Plan for PRC-024-2.

B. Requirements

- R1.** Each Generator Owner that has generator frequency protective relaying¹ activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the “no trip zone” of PRC-024 Attachment 1, subject to the following exceptions:² [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
 - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
 - Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R2.** Each Generator Owner that has generator voltage protective relaying¹ activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a

¹ Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

² For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

voltage excursion (at the point of interconnection³) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2.⁴ If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner’s study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation⁵ that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer’s advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.

³ For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

⁴ For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

⁵ Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.
- R4.** Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required.
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

C. Measures

- M1.** Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.
- M2.** Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.
- M3.** Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.

Standard PRC-024-2 — Generator Frequency and Voltage Protective Relay Settings

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	<p>The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings.</p> <p>OR</p> <p>The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.</p>	<p>The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings.</p> <p>OR</p> <p>The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.</p>	<p>The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings.</p> <p>OR</p> <p>The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.</p>	<p>The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings.</p> <p>OR</p> <p>The Generator Owner failed to provide trip settings within 150 calendar days of a written request.</p>

E. Regional Variances

None

F. Associated Documents

None

Version History

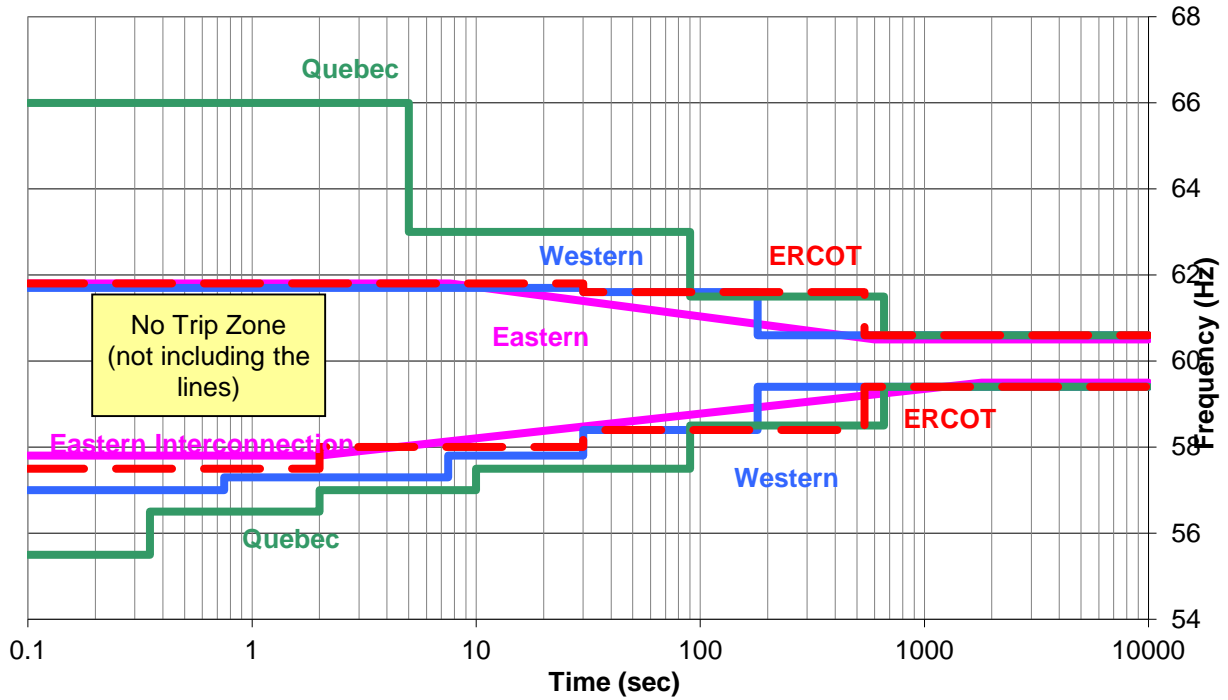
Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-024-2	Modifications to adjust the applicability to owners of dispersed generation resources.

G. References

1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Standard PRC-024-2 — Generator Frequency and Voltage Protective Relay Settings

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

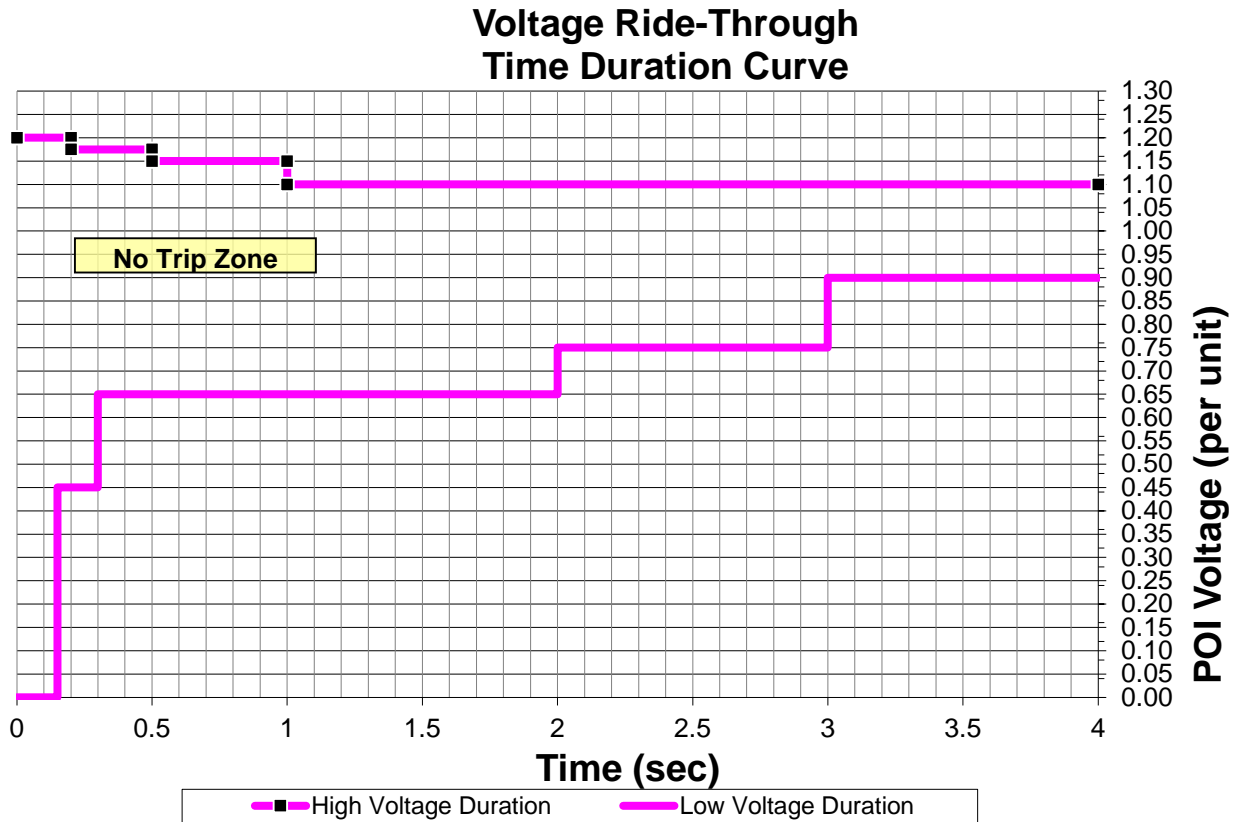
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
 - a. All of the units connected to the same transformer are online and operating.
 - b. All of the units are at full nameplate real-power output.
 - c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
 - d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Rationale:

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

Rationale for Footnotes 2 and 4

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting the “no-trip zone” referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

Appendix PRC-024-2-QC-1

Specific provisions applicable in Québec for standard PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of this appendix must be read jointly for comprehension and interpretation purposes. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. **Title:** No specific provisions.
2. **Number:** No specific provisions.
3. **Purpose:** No specific provisions.
4. **Applicability:**

4.1. Functional Entities

No specific provisions in regard to applicable entities.

The Facilities subject to this Standard are the Facilities of the Main Transmission System (RTP).

5. Effective date:

- 5.1. Adoption of the standard by the Régie de l'énergie: December 11, 2020
- 5.2. Adoption of this appendix by the Régie de l'énergie: December 11, 2020
- 5.3. Effective date of the standard and of this appendix in Québec: April 1, 2021

For Facilities already subject to PRC-024-1, the requirements will be implemented on the following dates:

Requirements	Applicability	Implementation date in Québec
R1 to R4	At least 40% of its Facilities covered	October 1, 2018
	At least 60% of its Facilities covered	October 1, 2019
	At least 80% of its Facilities covered	October 1, 2020
	100% of its Facilities covered	October 1, 2021

Appendix PRC-024-2-QC-1

Specific provisions applicable in Québec for standard PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

For Facilities newly subject to PRC-024-2, the requirements will be implemented on the following dates:

Requirements	Applicability	Implementation date in Québec
R1 to R4	At least 40% of its Facilities covered	July 1, 2022
	At least 60% of its Facilities covered	July 1, 2023
	At least 80% of its Facilities covered	July 1, 2024
	100% of its Facilities covered	July 1, 2025

B. Requirements

Specific provision regarding Requirement R1:

Wind, thermal and photovoltaic generating stations, as well as stations equipped with asynchronous generators, shall adhere to the curves in Appendix 1, as specified by Requirement R1, except that they may be tripped at a frequency of ≥ 61.7 Hz.

Specific provisions regarding Requirement R2:

Replace “PRC-024 Attachment 2” with “PRC-024-2-QC-1 Appendix 2” except for Generation facilities for industrial use which can replace “PRC-024 Attachment 2” with “PRC-024-2-QC-1 Appendix 3”.

Replace the first exception to Requirement R2 with the following: “A generating unit may be tripped in accordance with a Remedial Action Scheme (RAS).”

C. Measures

No specific provisions.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

In Québec, “Compliance Enforcement Authority” means the Régie de l’énergie in its roles of monitoring and enforcing compliance with respect to the Reliability Standard and to this appendix.

1.2. Data Retention

No specific provisions.

1.3. Compliance Monitoring and Assessment Processes

The Régie de l’énergie establishes the monitoring processes used to evaluate data or information for the purpose of determining compliance or non-compliance with the Reliability Standard and with this appendix.

1.4. Additional Compliance Information

Appendix PRC-024-2-QC-1

Specific provisions applicable in Québec for standard PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

No specific provisions.

2. Violation Severity Levels

No specific provisions.

E. Regional Variances

No specific provisions.

F. Associated Documents

No specific provisions.

G. References

No specific provisions.

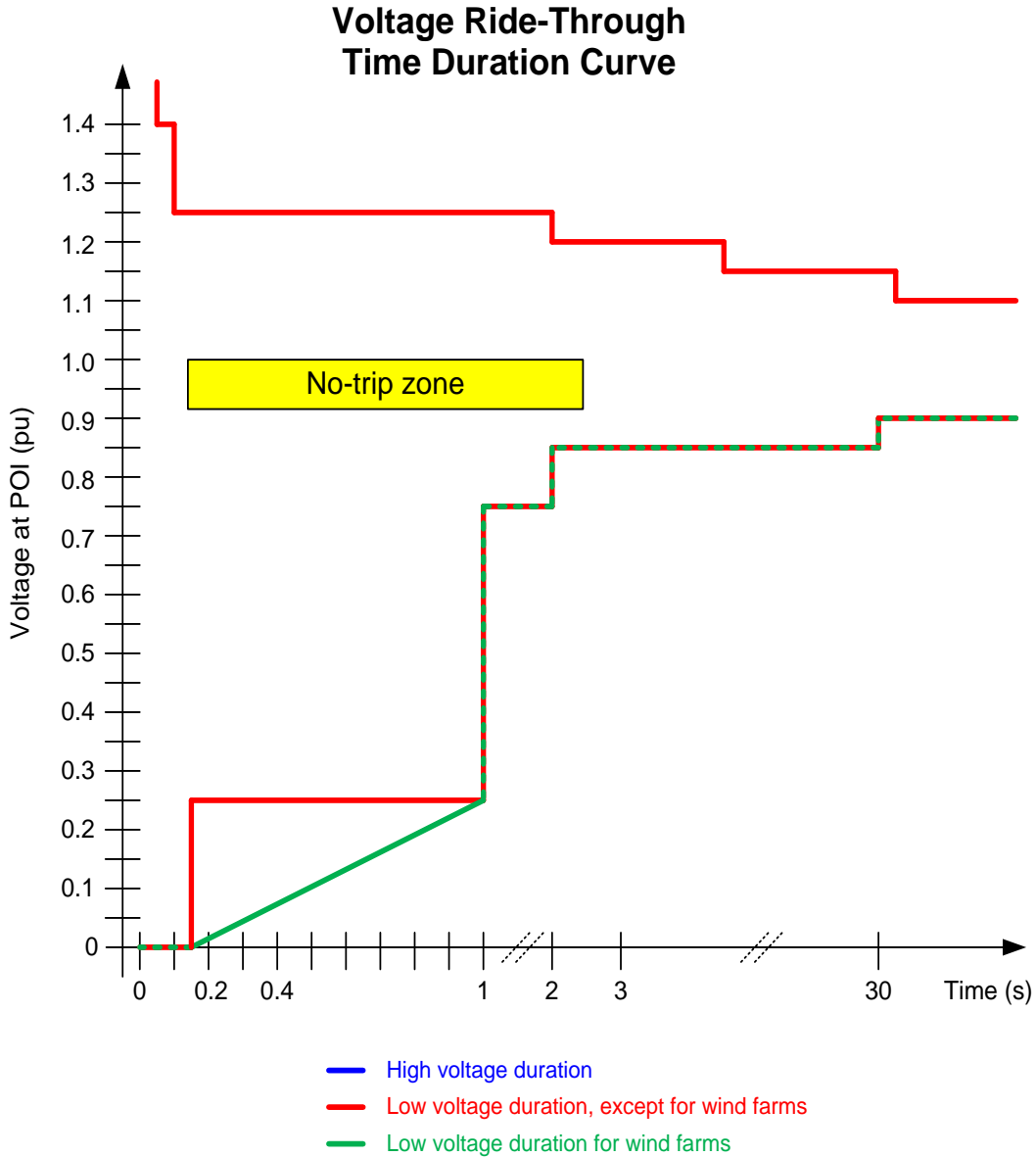
PRC-024 — Attachment 1

No specific provisions.

Specific provisions applicable in Québec for standard
PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

PRC-024-2 — Attachment 2

Replace the curve and table with the following:



Appendix PRC-024-2-QC-1

Specific provisions applicable in Québec for standard PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

Ride-Through Duration

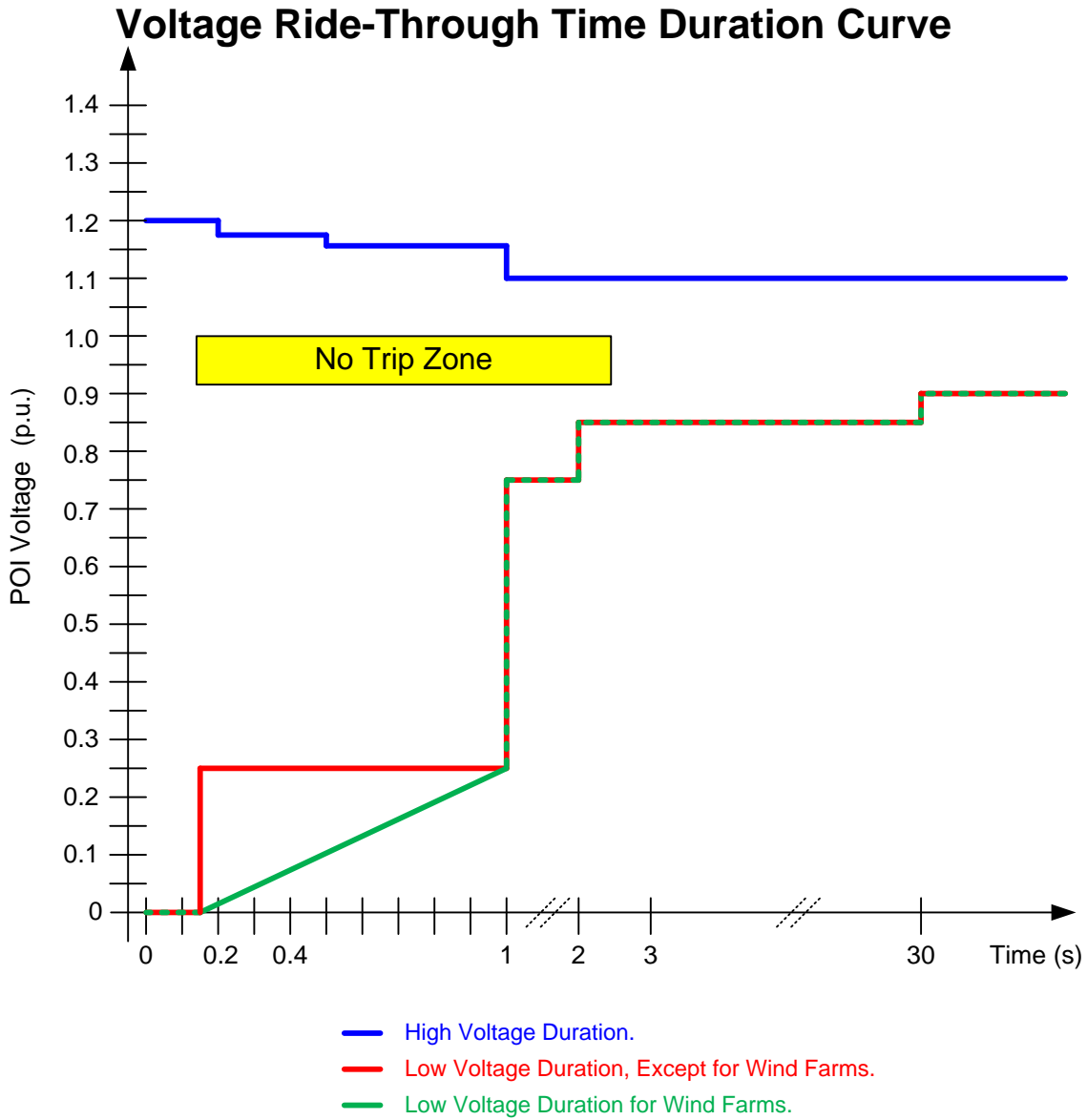
High Voltage Ride-Through Duration		Low Voltage Ride-Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
>1.4	0.033	$0.9 \leq V \leq 1.10$	permanent
$1.25 < V \leq 1.40$ (Note 1)	0.10	$0.85 \leq V < 0.9$	30
$1.20 < V \leq 1.25$	2.0	$0.75 \leq V < 0.85$	2.0
$1.15 < V \leq 1.20$	30.0	$0.25 \leq V < 0.75$	1.0
$1.10 < V \leq 1.15$	300	$0 \leq V < 0.25$ (Note 2)	0.15

Note 1. Temporary blocking is allowed, after a 0.022 sec delay, when the positive-sequence voltage exceeds 1.25 pu. However, normal operation must resume once the voltage drops back below the 1.25 pu threshold.

Note 2. For voltage levels between 0 and 0.25 pu, wind farms must observe the minimum duration calculated with the formula $D = 3.4 V + 0.15$, where D is minimum duration and V is voltage in pu.

Specific provisions applicable in Québec for standard
PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

PRC-024-1 — Attachment 3



Appendix PRC-024-2-QC-1

Specific provisions applicable in Québec for standard PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

Ride Through Duration :

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Duration (sec)	Voltage (pu)	Duration (sec)
$\geq 1,200$	Instantaneous trip	$.9 \leq V \leq 1.10$	Permanent
$\geq 1,175$	0,2	$.85 \leq V < .9$	30
$\geq 1,15$	0,5	$.75 \leq V < .85$	2.0
$\geq 1,10$	1,00	$.25 \leq V < .75$	1.0
		$0 \leq V < .25$ (note 1)	0.15

Note 1. For the voltage range between 0 and .25 pu, wind farms should respect the minimal duration calculated as following : $D = 3,4V + 0,15$, where D is the duration in second and V is the voltage in pu.

Rationale

No specific provisions.

Version history

Version	Date	Action	Change tracking
1	December 11, 2020	New appendix	New

