NORMES DE FIABILITÉ DE LA NERC
(VERSION ANGLAISE)

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-1**

3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plan(s) to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Effective Date:**

   See *Implementation Plan for EOP-011-1*

6. **Background:**

EOP-011-1 consolidates requirements from three standards: EOP-001-2.1b, EOP-002-3.1, and EOP-003-2.

The standard streamlines the requirements for Emergency operations for the Bulk Electric System into a clear and concise standard that is organized by Functional Entity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

1.2.6. Reliability impacts of extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

2.2.9. Reliability impacts of extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated e-mails or other correspondences that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators .

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

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 Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. 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 Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4and Measures M1 and M4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

If a Balancing Authority, Reliability Coordinator or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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:

As defined in the NERC Rules of Procedure; “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High		The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission s Operator Area but failed to implement it.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to implement it.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator.
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit tis Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency	The Reliability Coordinator that received an Emergency

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators but failed to notify within 30 minutes from the time of receiving notification.	notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

Attachment 1-EOP-011-1
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction
To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use.**

Circumstances:

- The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect**.

Circumstances:

- The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
- An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities **and market participants**. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress.

Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre-Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA**.**

0.1 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

Guidelines and Technical Basis

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 R1:

The EOP SDT examined the recommendation of the EOP Five-Year Review Team (FYRT) and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Operating Plan(s) for mitigating operating Emergencies in its Transmission Operator Area.

The Operating Plan(s) can be one plan, or it can be multiple plans.

"Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency" was retained. This is a process in the plan(s) that determines when the Transmission Operator must notify its Reliability Coordinator.

To meet the associated measure, an entity would likely provide evidence that such an evaluation was conducted along with an explanation of why any overlap of Loads between manual and automatic load shedding was unavoidable or reasonable.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R1 are not applicable, the Transmission Operator should note "not applicable" in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shed schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R1 Part 1.2.5. is to minimize, as much as possible, the use of manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If any entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review their automatic Load shedding schemes and coordinate their manual processes so that any overlapping use of Loads is avoided to the extent reasonably possible.

Rationale for R2:
To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1, the EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 also establishes a separate requirement for the Balancing Authority to create its Operating Plan(s) to address Capacity and Energy Emergencies.
The Operating Plan(s) can be one plan, or it can be multiple plans.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note "not applicable" in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

The EOP SDT retained the statement "Operator-controlled manual Load shedding," as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.2.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If an entity manually sheds a Load that was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review its automatic Load shedding schemes and coordinate its manual processes so that any overlapping use of Loads is avoided to the extent possible.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

Rationale for R3:
The SDT agreed with industry comments that the Reliability Coordinator does not need to approve BA and TOP plan(s). The SDT has changed this requirement to remove the approval but still require the RC to review each entity's plan(s), looking specifically for reliability risks. This is consistent with the Reliability Coordinator's role within the Functional Model and meets the FERC directive regarding the RC's involvement in Operating Plan(s) for mitigating Emergencies.

Rationale for Requirement R4:
Requirement R4 supports the coordination of Operating Plans within a Reliability Coordinator Area in order to identify and correct any Wide Area reliability risks. The EOP SDT expects the Reliability Coordinator to make a reasonable request for response time. The time period requested by the Reliability Coordinator to the Transmission Operator and Balancing Authority to update the Operating Plan(s) will depend on the scope and urgency of the requested change.

Rationale for R5

The EOP SDT used the existing requirement in EOP-002-3.1 for the Balancing Authority and added the words "within 30 minutes from the time of receiving notification" to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. By adding this time limitation, a measurable standard is set for when the Reliability Coordinator must complete these notifications.

Rationale for Introduction

LSEs were removed from Attachment 1, as an LSE has no Real-time reliability functionality with respect to EEAs.

EOP-002-3.1 Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, as permitted in its transmission tariff, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ E-tag Specification v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

Rationale for (2) Notification

The EOP SDT deleted the language, "*The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate system conditions. The RC shall also notify the other RCs when the alert has ended*" as duplicative to proposed IRO-014-3 Requirement R1:

> R1**.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
>
> **1.1** Communications and notifications, and the process to follow in making those notifications.
>
> **1.2** Energy and capacity shortages.
>
> **1.3** Control of voltage, including the coordination of reactive resources.
> Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.
>
> **1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas.
>
> **1.6** Provisions for weekly conference calls.

Rationale for EEA 2:

The EOP SDT modified the "Circumstances" for EEA 2 to show that an entity will be in this level when it has implemented its Operating Plan(s) to mitigate Emergencies but is still able to maintain Contingency Reserves.

Rationale for EEA 3:

This rationale was added at the request of stakeholders asking for justification for moving a lack of Contingency Reserves into the EEA3 category.

The previous language in EOP-002-3.1, EEA 2 used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA.

Appendix QC-EOP-011-1
Provisions specific to the standard EOP-011-1 applicable in Québec

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

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** EOP-011-1
3. **Purpose:** No specific provision
4. **Applicability:**

   No specific provisions

5. **Effective Date:**

   5.1. Adoption of the standard by the Régie de l'énergie: February 14, 2017

   5.2. Adoption of the appendix by the Régie de l'énergie: February 14, 2017

   5.3. Effective date of the standard and its appendix in Québec: April 2, 2017

6. **Background:**

   No specific provisions

B. Requirements and Measures

No specific provision

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

   1.2. Evidence Retention

   No specific provision

   1.3. Compliance Monitoring and Assessment Processes

   Compliance Audit

   Self-Certification

   Spot Check

   Compliance Investigation

   Non-Compliance Self-Reporting

   Periodic Data Submittal

   Exception Reporting

   Investigation following a complaint

1.4. Additional Compliance Information

No specific provisions

Table of Compliance Elements

No specific provision

D. Regional Differences

No specific provision

E. Interpretation

No specific provision

F. Associated Documents

No specific provisions

Attachment 1

No specific provisions

Guidelines and Technical Basis

No specific provisions

Revision History

Revision	Adoption Date	Action	Change Tracking
0	February 14, 2017	New Appendix	New

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.

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[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	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. OR (See next page)	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. OR (See next page)	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. OR (See next page)	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. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

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 letter[3] 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 Methodology[6]." 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.

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[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/RelaibilityCoordinationProject20066.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.

Example7c: 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).

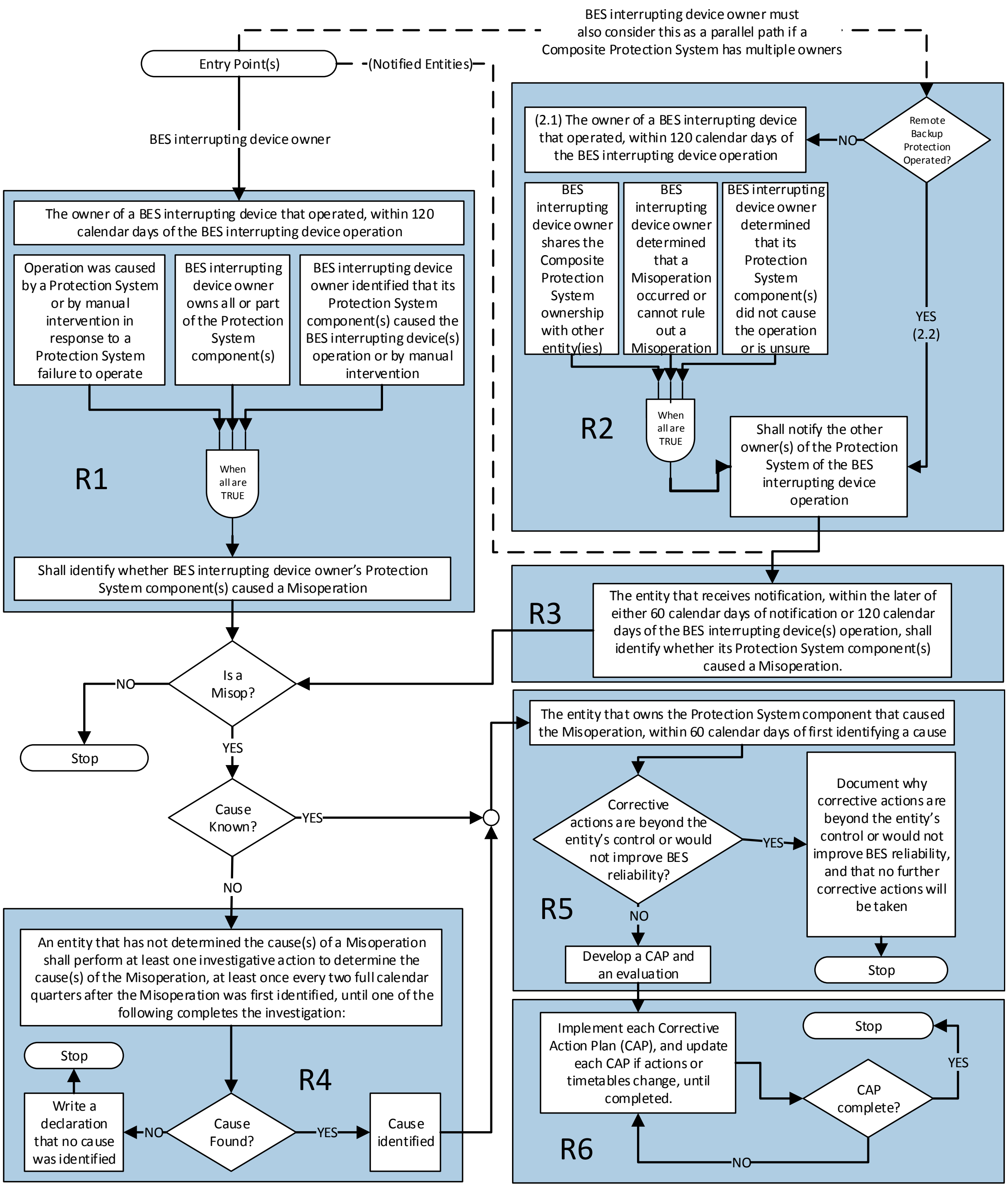
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance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


BES interrupting device owner must also consider this as a parallel path if a Composite Protection System has multiple owners
Entry Point(s)
(Notified Entities)
BES interrupting device owner
The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
Operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate
BES interrupting device owner owns all or part of the Protection System component(s)
BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or by manual intervention
When all are TRUE
R1
Shall identify whether BES interrupting device owner's Protection System component(s) caused a Misoperation
(2.1) The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
NO
Remote Backup Protection Operated?
BES interrupting device owner shares the Composite Protection System ownership with other entity(ies)
BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation
BES interrupting device owner determined that its Protection System component(s) did not cause the operation or is unsure
YES (2.2)
R2
When all are TRUE
Shall notify the other owner(s) of the Protection System of the BES interrupting device operation
R3
The entity that receives notification, within the later of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation.
NO
Is a Misop?
Stop
YES
Cause Known?
YES
NO
The entity that owns the Protection System component that caused the Misoperation, within 60 calendar days of first identifying a cause
Corrective actions are beyond the entity's control or would not improve BES reliability?
YES
Document why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken
R5
NO
Develop a CAP and an evaluation
Stop
An entity that has not determined the cause(s) of a Misoperation shall perform at least one investigative action 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:
Stop
R4
Write a declaration that no cause was identified
NO
Cause Found?
YES
Cause identified
Implement each Corrective Action Plan (CAP), and update each CAP if actions or timetables change, until completed.
Stop
YES
CAP complete?
R6
NO

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 QC-PRC-004-5(i)
Provisions specific to the standard PRC-004-5-(i) applicable in Québec

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

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**
2. **Number:** PRC-004-5(i)
3. **Purpose:** No specific provision
4. **Applicability:**

   This standard only applies to the Facilities of the Bulk Power System (BPS).

5. **Effective Date:**

   5.1. Adoption of the standard by the Régie de l'énergie: February 14, 2017

   5.2. Adoption of the appendix by the Régie de l'énergie: February 14, 2017

   5.3. Effective date of the standard and its appendix in Québec: April 2, 2017

B. Requirements and Measures

No specific provision

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

   1.2. Evidence Retention

   No specific provision

   1.3. Compliance Monitoring and Assessment Processes

   No specific provision

   1.4. Additional Compliance Information

   No specific provisions

D. Table of Compliance Elements

No specific provision

E. Regional Variances

No specific provision

F. Interpretations

No specific provision

G. Associated Documents

No specific provisions

Guidelines and Technical Basis

No specific provisions

Rationale

No specific provisions

Revision History

Revision	Adoption Date	Action	Change Tracking
0	February 14, 2017	New Appendix	New

A. Introduction

1. **Title:** Undervoltage Load Shedding
2. **Number:** PRC-010-2
3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

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

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity 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 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 Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2	May 7, 2015	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.

Guidelines and Technical Basis

Introduction

The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

Guidelines for UVLS Program Definition

The definition for the term, “Undervoltage Load Shedding Program” or “UVLS Program” includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between buses A and B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading, a UVLS system (installed at either, or both, bus B and D) used to mitigate this Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.

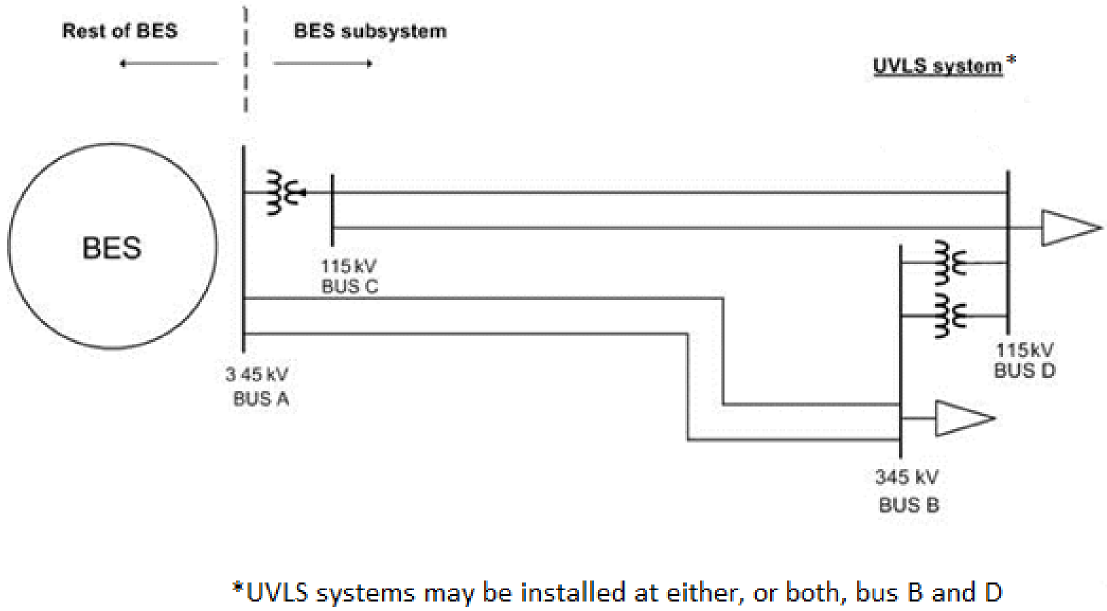


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview						
Requirement	**Entity**	**Evaluate Program Effectiveness**	**Adhere to Program Specifications and Schedule**	**Perform Program Assessment (Periodic or Performance)**	**Develop a CAP to Address Program Deficiencies**	**Update and/or Share Program Data**
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the Misoperation[1] of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

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[1] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment is required to be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[2] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment complements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4

After a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event is performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are

[2] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[3]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

Guidelines for Requirement R5

Requirement R5 promotes the prudent correction of an identified problem during the assessment of a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The "within three

[3] Id.

calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted
- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS), and RAS

Additionally, the UVLS Program database is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well- accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[4,5] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[6] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[7] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[8] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[9] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

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[4] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding).
[5] Adopted by the NERC Board of Trustees on November 14, 2014.
[6] (http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx).
[7] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx).
[8] (http://www.nerc.com/docs/docs/ferc/order_693.pdf).
[9] (http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf).

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[10] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[11]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[12] Requirements R2, R4, and R7 as being more properly covered by Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and

[10] (http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf).
[11] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.
[12] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans).

consolidate EOP-001-2.1b (*Emergency Operations Planning*),[13] EOP-002-3 (Capacity and Energy Emergencies),[14] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2 requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[15] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[16] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition excludes locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and

[13] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning).
[14] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies).
[15] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations).
[16] (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).

PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[17] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage

[17] Adopted by the NERC Board of Trustees on November 14, 2014.

instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[18] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner

[18] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion) to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[19] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

[19] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis).

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[20]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[21,22] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

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 Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning

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[20] Refer to Standards Independent Expert Review Project (IERP). (http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf).
[21] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding).
[22] Adopted by the NERC Board of Trustees on November 14, 2014.

Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

Appendix QC-PRC-010-2
Provisions specific to the standard PRC-010-2 applicable in Québec

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

A. Introduction

1. **Title:** **Undervoltage Load Shedding**
2. **Number:** PRC-010-2
3. **Purpose:** No specific provision
4. **Applicability:**

   None.

5. **Effective Date:**

   5.1. Adoption of the standard by the Régie de l'énergie: February 14, 2017

   5.2. Adoption of the appendix by the Régie de l'énergie: February 14, 2017

   5.3. Effective date of the standard and its appendix in Québec: April 2, 2017

B. Requirements and Measures

No specific provision

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

   1.2. Evidence Retention

   No specific provision

   1.3. Compliance Monitoring and Assessment Processes

   Compliance Audit

   Self-Certification

   Spot Check

   Compliance Investigation

   Non-Compliance Self-Reporting

   Periodic Data Submittal

   Exception Reporting

   Investigation following a complaint

   1.4. Additional Compliance Information

   No specific provisions

Appendix QC-PRC-010-2
Provisions specific to the standard PRC-010-2 applicable in Québec

Table of Compliance Elements

No specific provision

D. Regional Variances

No specific provision

E. Interpretations

No specific provision

F. Associated Documents

No specific provisions

Guidelines and Technical Basis

No specific provisions

Revision History

Revision	Adoption Date	Action	Change Tracking
0	February 14, 2017	New Appendix	New